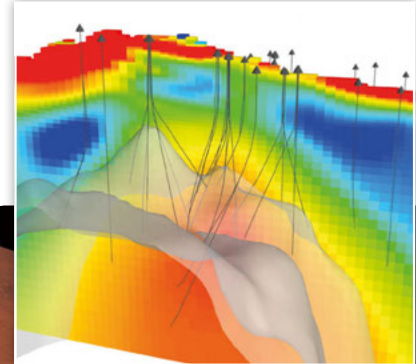
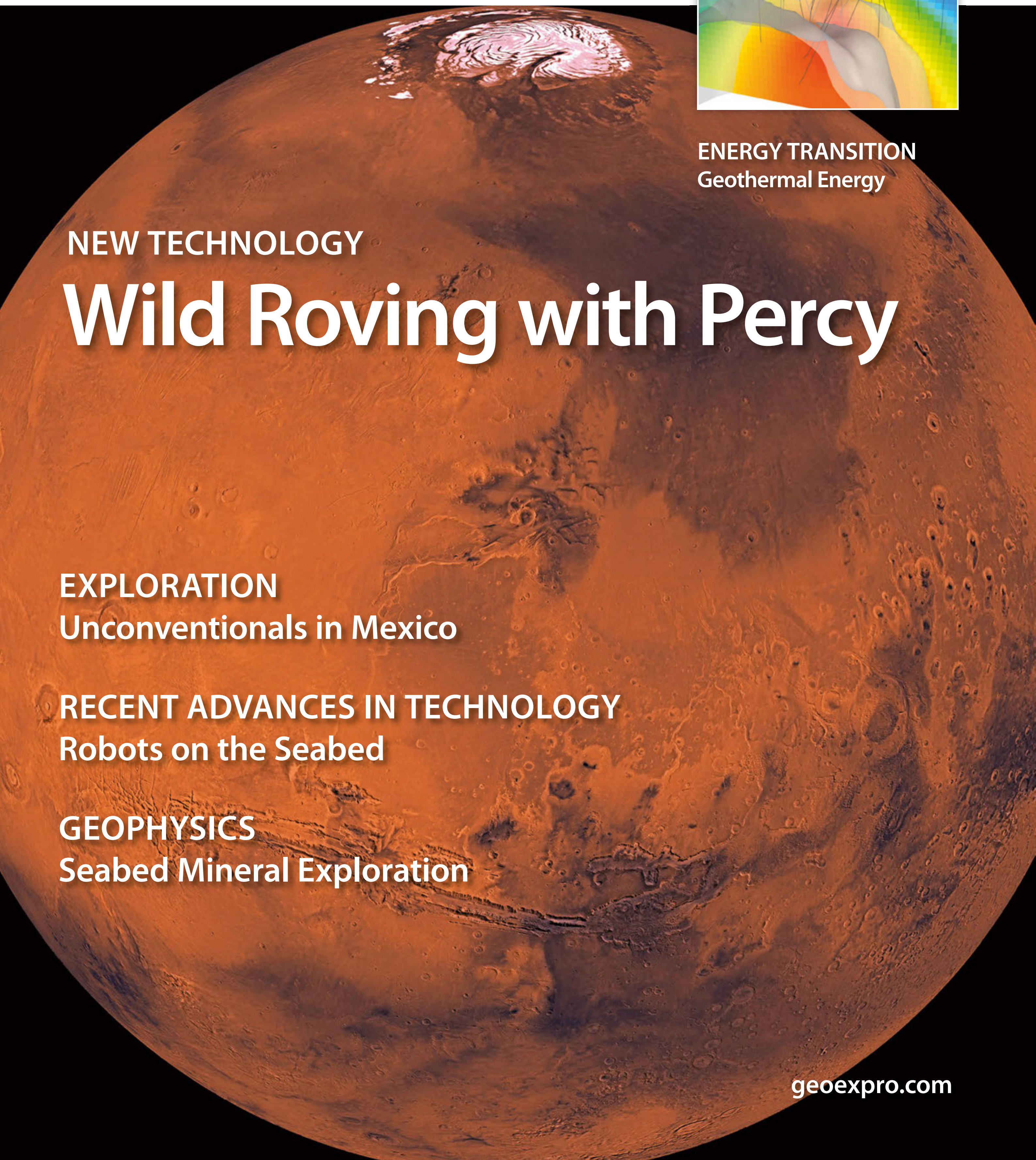
VOL. 18, NO. 3 – 2021

GEOExPro

GEOSCIENCE & TECHNOLOGY EXPLAINED



ENERGY TRANSITION
Geothermal Energy



NEW TECHNOLOGY

Wild Roving with Percy

EXPLORATION
Unconventionals in Mexico

RECENT ADVANCES IN TECHNOLOGY
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GEOPHYSICS
Seabed Mineral Exploration

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Mexico's Tampico-Misantla Basin is potentially one of the richest unconventional oil and gas resources in the world and development of these resources could significantly increase Mexico´s oil and gas production, bringing sufficient income to rejuvenate the national oil company and help get the Mexican economy back on its feet.


Lon Abbott/Terri Cook

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Dalmatia, the famously beautiful and rugged coastline stretching between Montenegro's Bay of Kotor north to Croatia's Rab island. It, like the French Riviera, is a destination made to savour on a bike tour, on foot, or in a convertible with the top down.


ETH - Zurich

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Oil was first exploited commercially in Romania in 1857 and, since then, the industry has seen cycles of boom and bust, prosperity and decline. Romanians have a proud technological and geological record in the oil industry, but international rivalry brought a troubled narrative to the story of their land.

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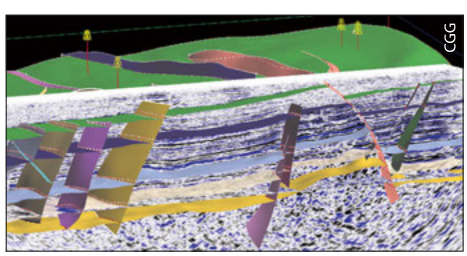
Like oil and gas reservoirs, there are many different geothermal play types, yet there remain some constant geological factors that must be understood and oil and gas explorationists will find their skills are very transferable to this energy source.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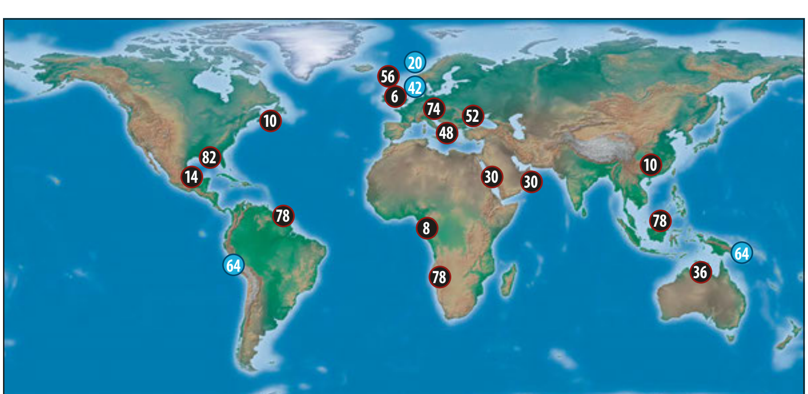

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This issue of *GEO ExPro* focuses on Europe; Robotics and Automation; Unconventional Resources and the Energy Transition.

Are Friends Electric?

A drone, monitoring oil refinery.

Upstream exploration requires the utilisation and adaptation of different technologies distributed over numerous scientific and engineering disciplines. As the cost of exploration and exploitation of resources rises, more efficient ways of working become more and more critical. Automation is an area of rapid development in many industries; if you have seen the YouTube videos of order picking robots in Amazon's 'smart' warehouses, you can understand how impressive and disruptive these types of technologies can be. In the offshore energy industries, we are seeing similar innovations with highly automated systems in marine seismic acquisition and the potential advent of fully autonomous robotic ocean bottom node systems as well as inspection robots on offshore facilities.

Robotics is not limited to planet Earth, as is dramatically illustrated by the incredible, successful delivery of NASA's Perseverance rover to the 45 km-wide Jezero impact crater. Not only did 'Percy' arrive unscathed after its 480 million kilometre journey, but it was delivered to the surface of the red planet by its personal, jet-powered delivery system – all remotely and pre-programmed. It also carried a passenger called Ingenuity, a small coaxial, drone rotorcraft whose individual mission will be to help guide Percy on its onward journey through Jezero. Already successfully tested, it will have the potential to scout locations of interest and support the future planning of driving routes for future Mars rovers.

Remote satellite monitoring, coupled with machine learning and high-performance computing, is allowing a range of industries to strengthen situational awareness of the impact of offshore assets, coastal facilities, and vessel activity on the natural marine environment. As well as gas flaring, early detection of anomalous events and third-party pollution incidents, and surveillance of natural seeps are all becoming more common as the number of satellites available for commercial use increases.

Closer to home, automation will be a key driver in the technologies deployed for seabed mining – if this ever becomes a reality. Our article on seabed mineral exploration suggests that some of the reconnaissance phases of exploration could be undertaken using autonomous underwater vehicles equipped with a range of sensors capable of collecting multiple datasets in a single dive. These would augment the use of wide-tow sources and variable multisensor streamer geometries. Geophysical technology, modified for studying the shallow subsurface and deployed from efficient autonomous platforms, has the potential to provide information to make better environmental decisions and to guide responsible exploitation of marine mineral resources. ■

Iain Brown
Editor in Chief

WILD ROVING WITH PERCY

Undoubtedly the most advanced example of automation and robotics engineered by humans, Perseverance (Percy), the NASA Mars rover has started its epic mission to search for extra-terrestrial life. The quest will be guided by geology, making Percy the first robotic geologist to operate off-world.

Inset: A 3D structural model of the Upper Rhine Graben, built from interpreted seismic volumes to help inform well planning for geothermal energy.

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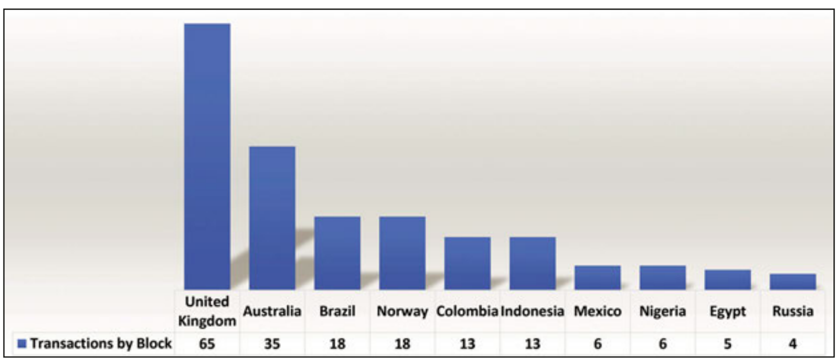
Private Equity Firms Drive UK Oil and Gas Activity

Since the first hydrocarbons were produced on the UK Continental Shelf at BP's West Sole gas field in 1967, there have been many prophecies of when production from the province would eventually end. To use that well-known phrase from the oil industry, 'it is a hydrocarbon province that keeps on giving'.

With such prolific source rocks, notably in the Jurassic and Carboniferous, we can expect more surprises in the offshore basins. The industry can also expect many oil and gas fields will outlast their prognosed depletion dates and be the subject of re-development in the future.

Despite a drop in new exploration and appraisal drilling in the UK offshore sector, the industry remains very buoyant compared to other parts of the world. Bid rounds continue to be healthy with new block awards, and we also see robust deal flow. London itself has taken over from Houston as the global hub for international oil and gas deals.

The figure below shows the number of contract areas which have been the subject of a transaction between 2016 to 2020. The UK has been the most active place in the world outside of North America with 2018 and 2020 being the busiest years in the UK. Much of this has been driven by Private Equity (PE) involvement which started its drumfire in 2015.



Global oil and gas transactions, 2016–2020.

The main PE firms are the Carlyle Group, HitecVision, Quantum Energy Partners, Blackstone Group, CVC Capital Partners, Blue Water Energy, Kerogen Capital, Riverstone and EIG Partners. Oil companies backed by these firms include Siccar Point, Chrysaor (now Harbour Energy), Neptune Energy, NEO Energy and Waldorf Production.

In addition, there are numerous divestment opportunities available in the UK offshore. In fact the UK has the second largest number of upstream opportunities available in the 2018–2021 period after Australia. This highlights the competition companies face when seeking farmout partners or the sale of assets in the UK.

The quality of technical work on these assets for divestment is extremely high, and is combined with positive government energy policies managed by the Oil and Gas Authority (OGA).

Success in several high-profile wells scheduled in 2021 will increase interest in a number of these divestment opportunities. These include Shell's Edinburgh Prospect in the Central North Sea and its Pensacola Prospect on the Mid North Sea High, and Equinor's Tiger Lily Prospect in the Central North Sea.

Despite the mature nature of its fields, the UK still generates a lot of cash, making it attractive to investors with break-even in the US$30 to US$50 range. We see deal flow continuing to be very active going forward, but with the pool of buyers getting smaller, capital is going to fight for good trade terms. It also remains to be seen what the exit strategy is for PE firms, or will they stay and maintain their cash flows? ■

Ian Cross, Moyes & Co

ABBREVIATIONS

Numbers
(US and scientific community)

M: thousand = 1×10^3
MM: million = 1×10^6
B: billion = 1×10^9
T: trillion = 1×10^{12}

Liquids
barrel = bbl = 159 litre
boe: barrels of oil equivalent
bopd: barrels (bbls) of oil per day
bcpd: bbls of condensate per day
bwpd: bbls of water per day
stoiip: stock-tank oil initially in place

Gas
MMscfg: million ft^3 gas
MMscmg: million m^3 gas
Tcfg: trillion cubic feet of gas

Ma: Million years ago

LNG
Liquified Natural Gas (LNG) is natural gas (primarily methane) cooled to a temperature of approximately -260 °C.

NGL
Natural gas liquids (NGL) include propane, butane, pentane, hexane and heptane, but not methane and ethane.

Reserves and resources
P1 reserves:
Quantity of hydrocarbons believed recoverable with a 90% probability

P2 reserves:
Quantity of hydrocarbons believed recoverable with a 50% probability

P3 reserves:
Quantity of hydrocarbons believed recoverable with a 10% probability

Oilfield glossary:
www.glossary.oilfield.slb.com

Angola's ANPG Promotes Onshore Exploration

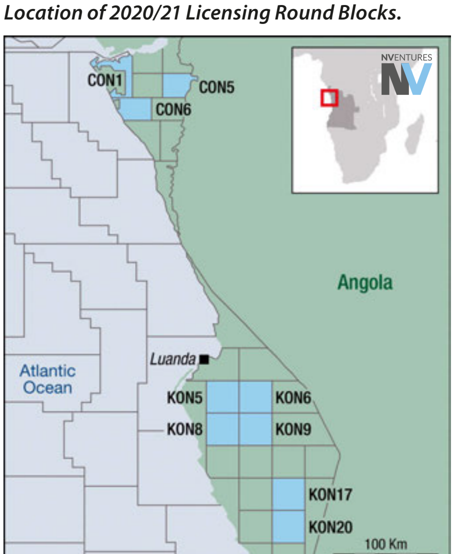
In mid-April this year, Angola's National Oil, Gas and Biofuels Agency (ANPG) started a virtual and physical roadshow for its 2020/21 bid round, with promotional activity commencing in the capital Luanda. The acreage on offer comprises a total of nine onshore blocks, CON1, 5 and 6 in the Lower Congo Basin and blocks KON5, 6, 8, 9, 17 and 20 in the Kwanza Basin. This latest licensing round was launched on 30 April and will conclude on 9 June with contracts currently forecast to be signed on 22 November. Interested parties are encouraged to seek one-on-one meetings with the ANPG to discuss participation in further detail and a promotional video is also available.

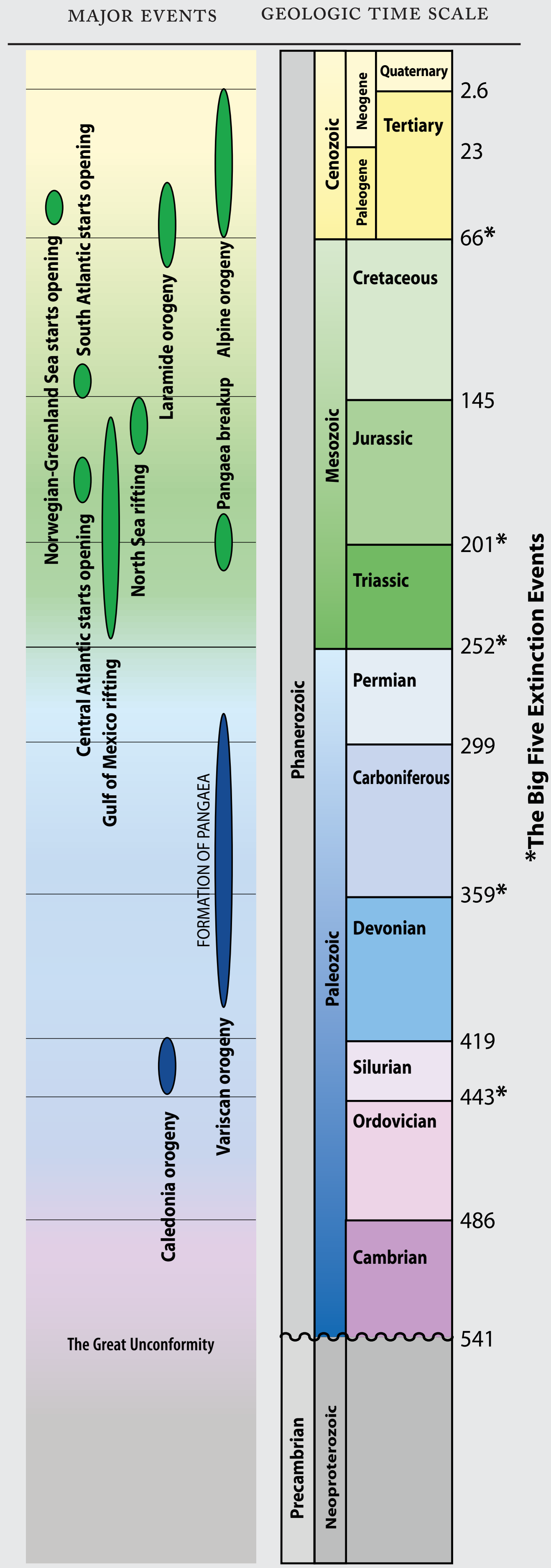
Onshore exploration activities in Angola have led to the discovery of over a dozen commercial oil fields and one natural gas field, with reserves ranging between five and 40 MMbo. It is thought that there is significant upside potential untapped in deeper targets in both the rift and transitional phase reservoirs.

ANPG is also seeking to increase the number of companies exploring in Angola by granting potential investors access to data packages before purchasing them, helping to minimise cost and risk, and improving transparency in the process. Data packages are available for the onshore basins, providing key geological information, including dedicated reports on the stratigraphy, structural analysis and hydrocarbon potential of each area. Studies on infrastructure, GIS data and relevant legal, fiscal and commercial information are also available, together with vintage seismic data for the Kwanza Basin.

An evaluation of Angola's oil and gas prospects, conducted at the end of 2020, increased estimated reserves to 57 Bbo and 27 Tcfg, from previous estimates of 8.2 Bbo and 13.5 Tcfg, giving Angola the largest oil reserves in Africa. The better known offshore deep- and ultra-deep water exploration areas have attracted most attention from operators and the Kwanza Shelf is of increasing interest due to new broadband 3D seismic data and several successful exploration wells. Geologically, the shallow-water shelf is considered to be a good analogue for the prolific Santos and Campos Basins in Brazil, and has had several early discoveries in Blocks 20, 21 and 23 – including the Orca field, which is considered to be one of the largest pre-salt discoveries in the Kwanza Basin so far. ANGP have announced they will work towards awarding more than 50 exploration blocks from deepwater areas to shallow basins through 2025, so more offshore blocks are expected to be offered in the next few years. ■

Location of 2020/21 Licensing Round Blocks.





Robots De-Risk Inspections

Equinor is introducing autonomous **ATEX-certified** robots on their oil and gas installations. ATEX stands for atmosphères explosibles and is a European Union directive that covers equipment intended for use in potentially explosive atmospheres. Austrian robotics company, **Taurob**, is the partner in the project, which will see the robots used for routine inspection and maintenance tasks on offshore installations.

Taurob started developing robotics principally for emergency response situations and safety is the main driver for the energy sector to step into robotics. The 'Taurob Inspector' robot has evolved from a two-year collaboration between Taurob, French energy company Total and UK's OGTC. Total was the first energy major to implement robotic inspection on their plant in the North Sea's Shetland Islands.

Equinor joined **Total**, **OGTC** and Taurob in 2019 on the **ARGOS Joint Industry Project** to develop a completely new, low maintenance robot, capable of performing autonomous manipulation operations, making them ideal for Normally Unmanned Facilities (NUFs) where human intervention is limited. As a so-called 'Work Class' robot, it will physically interact with the installation and testing will be performed later this year. ■

SEG and AAPG Combine Annual Meetings

The American Association of Petroleum Geologists (AAPG) and the Society of Exploration Geophysicists (SEG) are excited to announce plans for joint annual meetings beginning **26 September to 1 October 2021**, at the Colorado Convention Center in Denver, Colorado. This event will mark the first time the two groups' annual conventions have been held together since 1955.

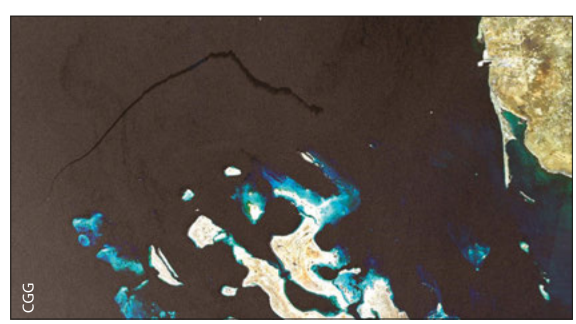
The merger of **ACE 2021** and **SEG's 2021 International Exhibition and 91st Annual Meeting (SEG21)** will result in one of the largest gatherings of earth scientists and energy professionals in the world. The two events will be fully integrated, online and in-person, with a comprehensive technical programme featuring more than 20 concurrent technical sessions and a joint exhibition featuring the latest geoscience products and technologies.

One registration will give delegates access to the core technical sessions and exhibition and access to several ticketed training and social events. Exhibitors and sponsors will benefit from access to two audiences with a single engagement.

Watch for full programme, exhibition, and registration details coming soon. ■

Environmental Monitoring from Space

Gas Flaring is coming under increasing scrutiny as there is renewed focus on this practice ahead of **COP26** later this year. Capterio, a company which uses independent and verified third-party satellite data to track gas flares, released its free-to-download FlareIntel application recently. This accesses data related to the volume of every gas flare, its associated revenue potential if captured, and its CO_2-equivalent emissions. It is also aggregated for country level analysis. With this level of transparency available to the public, it can surely only add pressure on governments and companies to start seriously addressing this issue.



Vessel pollution in the Red Sea captured by the ESA Sentinel-1 satellite (contains modified Copernicus Sentinel data [2021]).

In May this year, geoscience technology company, **CGG** launched **SeaScope**, a new pollution monitoring solution, which forms part of its portfolio of products and services for environmental applications. This system combines remote sensing science, Earth observation data, machine learning and high-performance computing to provide sea surface slick intelligence to strengthen situational awareness of the interaction between offshore assets, coastal facilities, local vessel activity and the natural marine environment. The solution was developed with the support of the **European Space Agency** together with a group of energy companies and emergency response organisations. This new monitoring system will help offshore industries to mitigate risks, respond quickly to events and support environmental and operational transparency, and related ESG commitments. ■

URTeC 2021 In-Person and Online

The Unconventional Resources Technology Conference **(URTeC)** continues to be the premier event focused on the latest science and technology applied to exploration and development of unconventional resources, with special emphasis on integration of multiple disciplines.

With record-breaking attendance, hundreds of packed technical presentations, and an incredible industry response at URTeC 2017, 2018, and 2019, there is no doubt that the URTeC has been an overwhelming success.

URTeC entered the digital space in 2020, responding proactively to Covid-19 and low energy prices, with an innovative virtual event featuring more than 250 technical talks, panel discussions, and team presentations. URTeC plans to move forward with a hybrid event **26–28 July 2021** in-person at the **George R. Brown Convention Centre** in Houston, Texas and online. Hear first-hand from experts working in the most exciting unconventional plays, and gain insight into strategies for 2021 and beyond.

URTeC's combination of the world's leading professional societies has brought both depth and breadth to the technical base of the conference which has attributed to the URTeC's collaborative platform and innovation exchange, sustaining and propelling our industry's ongoing success.

Visit the URTeC 2021 website to register and to see the full line-up of talks, sessions, panels, short courses, and more. ■

Will China Shale Gas Attract?

A **2013 US EIA study** estimated China held the world's largest shale gas resources at over 1,160 Tcf. Since then, the Chinese shale gas sector has failed to meet growth expectations. Complex geology, coupled with significant above ground challenges – including topography, high population density and water access – and weak fiscal and regulatory support has kept costs high. Numerous IOCs with significant shale experience evaluated the opportunities, but few committed and today the only significant players are **PetroChina** and **Sinopec**, with almost all activity limited to the **Sichuan Basin** in central China.

Despite this, China's shale gas production increased to over 1.9 Bcfd in 2020, an impressive 30% year-on-year jump. Whilst this was only two-thirds of the government's 2020 target, it remains a credible performance. PetroChina and Sinopec are reinventing domestic shale gas development by chasing shale formations in far deeper formations than those in the US. Most of the current shale production comes from the Sichuan Basin's so called middle shale plays (2,000–3,500 metres depth). The NOCs have made significant progress understanding the geology there, and appraisal and development is now turning to deeper resources at depths ranging from 3,500 to over 4,500 metres.

Deeper wells inevitably mean higher costs and reducing these costs will require new technologies and less reliance on foreign suppliers. **Wood Mackenzie** recently upgraded its forecasts on production growth based on NOC's progress, but this will rely upon whether the deep shale in the southern Sichuan Basin, which they see as having huge untapped potential, can be successfully exploited. ■

23rd World Petroleum Congress

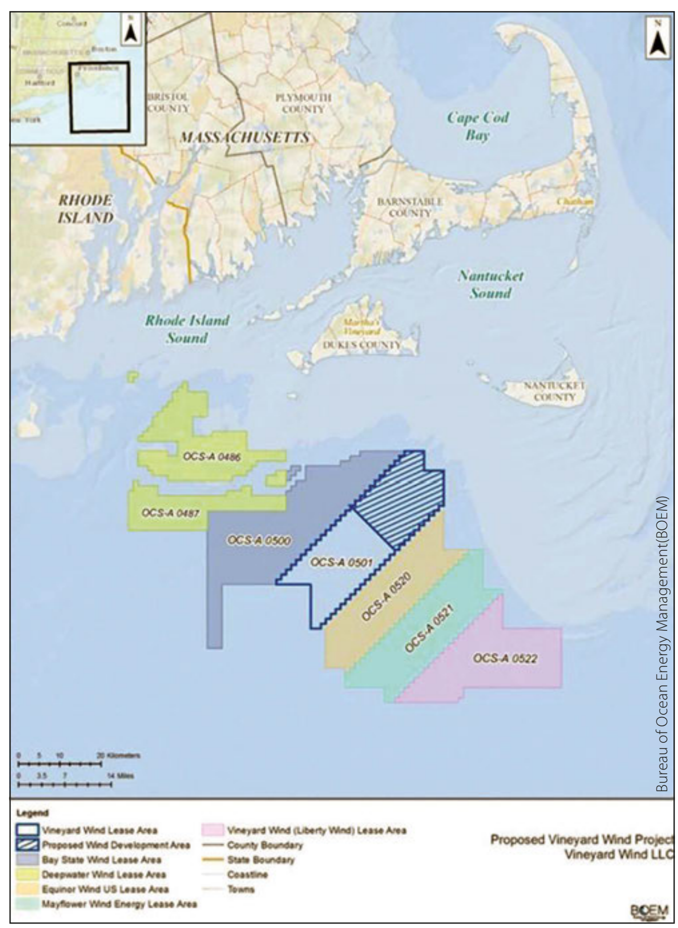
World Petroleum Congress

Reflecting the amazing technological developments seen over the years in the industry, the theme of the upcoming **23rd World Petroleum Congress** – ‘Innovative Energy Solutions’ – will run through both the Congress programme and exhibition.

Through a series of high-level plenaries and round tables, senior government officials and executives will share global insights into the energy transition and future of the industry, touching on collaboration, harnessing big data and other industry priorities. Alongside the strategic programme will be an extensive technical programme, comprising a variety of interactive session formats, including forums, round tables and workshops. Thematic highlights include: innovative E&P technologies and the future landscape of E&P technology, seismic data, cybersecurity, new petroleum resources, the impact of digitalisation in the upstream sector and improving industry performance.

The 23rd World Petroleum Congress will take place in person from **5–9 December 2021** in Houston, USA. ■

Vineyard Wind Project Signals US Move to Offshore Renewables



Bureau of Ocean Energy Management (BOEM)

The Biden administration has announced approval of the construction and operation of the **Vineyard Wind project** – the first large-scale, offshore wind project in the United States. The proposed **800-megawatt** energy project will contribute to the goal of generating 30 gigawatts of energy from offshore wind by 2030. Located 12 nautical miles **offshore Nantucket** in the northern portion of Vineyard Wind’s lease area, it will create 3,600 jobs and provide sufficient power for almost half a million homes and businesses.

The Biden administration has galvanised the offshore wind industry in the US by announcing the first ever national offshore wind energy mandate, creating a federal plan for the future of this industry. Achieving the 30-gigawatt goal is anticipated to result in the creation of thousands of new jobs while reorienting America’s attitude towards renewable energy and helping to meet global zero-carbon targets. Developing the offshore wind supply chain to allow wind turbine manufacturing in both inland areas and on the coasts, will help sustain several local US industries.

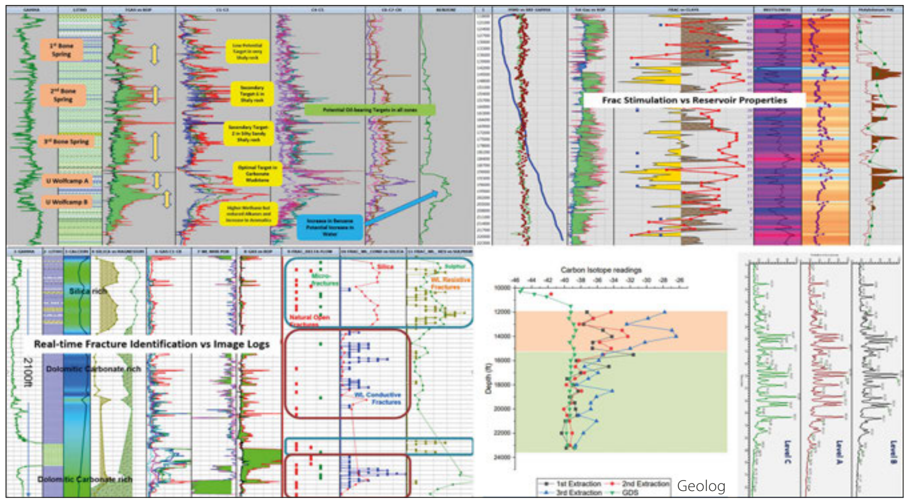
The Record of Decision (ROD) grants Vineyard Wind final federal approval to install up to 84 wind turbines off Massachusetts. The turbines will be installed in an east–west orientation, and all the turbines will have a minimum spacing of 1 nautical mile in the north–south and east–west directions, consistent with the US Coast Guard recommendations. The ROD adopts mitigation measures to help reduce or eliminate adverse environmental effects resulting from the construction and operation of the proposed project. These measures were developed through input, consultation, and coordination with all stakeholders, Tribes, and federal and state agencies.

In addition to the Vineyard project, the **US Department of the Interior** has initiated the environmental review of two other offshore wind projects and pursued additional leasing opportunities in the New York Bight. ■

Unconventional Formation Evaluation: Advanced Surface Logging Solutions

Ongoing market pressure has led operators to focus on cost-control, seeking improved value from services delivering well data. **GEOLOG Surface Logging** has developed solutions utilising mud gas and drill cuttings to deliver hydrocarbon and formation characterisation: helping operators understand reservoirs, drill efficiently, predict production potential and improve well placement and completion strategies.

By applying advanced rig site analysis of hydrocarbon composition from mud gas and drill cuttings from C1 to C27 alongside C1 to C3 carbon isotopes, GEOLOG delivers fluid typing, heterogeneity/compartmentalisation assessment, gas maturity data, reservoir sealing and biodegradation information. Combined with analysis of cuttings mineralogy, lithology, clay type, chemical composition, total organic carbon, source rock maturity and formation potential, a comprehensive suite of critical reservoir information is achievable whilst drilling.



GEOLOG's patented real-time monitoring of micro fluid losses, integrated with drilling parameters and formation evaluation data allows identification and characterisation of pre-existing and drilling-induced fractures in real time, facilitating completion decisions. Analysis of cuttings headspace gas allows relative permeability and reservoir heterogeneities in laterals to be understood, further improving completion planning and well economics. By utilising these surface technologies, results are achieved without the risk and costs of downhole tools. ■

Unconventionals in Mexico

A missed opportunity?

ALFREDO E. GUZMÁN

Mexico's Tampico-Misantla Basin is potentially one of the richest unconventional oil and gas resources in the world, with reserves of at least 90 Bbo and 40 Tcfg. Development of these resources could significantly increase Mexico's daily production of oil and gas, bringing in enough income to rejuvenate the national oil company, PEMEX, and help get the economy back on its feet. Perplexingly, little is being done to bring these resources into production.

The Tampico-Misantla Basin

The Tampico-Misantla Basin is in east-central Mexico, bounded by the Tamaulipas Arch in the north, the Gulf of Mexico in the east, the Neovolcanic Axis and Teziutlán uplift in the south, and the Sierra Madre Oriental Fold Belt to the west.

Figure 1: Mexico's oil and gas basins. Tampico-Misantla is one of only two that produce oil.

In 2016, IHS Markit analysts developed the super basin concept and proposed the Permian Basin of West Texas and Eastern New Mexico as the epitome of a super basin. They also identified the Tampico-Misantla Basin as a super basin that has very similar characteristics to the Permian Basin, recognising it as an excellent candidate for rejuvenation (Fryklund and Stark, 2020; Sternbach, 2020; Guzmán, 2021).

The Permian Basin started production in the 1920s from reef- and shelf-limestone reservoirs that rim the Delaware and Midland Sub-basins. It reached 2 MMbopd production in the mid-1970s, declining steadily thereafter until by 2010 output had declined to less than 1 MMbopd, when the advent of horizontal drilling with multiple hydraulic fractures allowed oil and gas to flow economically from silts and shales previously overlooked as producible reservoirs. This resulted in exponential production growth that in only 10 years reached a staggering 4.8 MMbopd and 18 Bcfpd. In 2020 the Covid-19 pandemic hampered growth, but by early 2021 it had resumed, albeit at a slower rate. The basin's resource estimate of 30 Bboe in the early 2000s was reassessed in 2018 to be 150 Bboe recoverable.

Tampico-Misantla has four main conventional oil plays that were the focus of upstream activity in Mexico until the 1980s. The first reservoirs were discovered in the early 1900s in fractured carbonates of the prolific Ébano-Pánuco-Cacalilao Province west of Tampico, followed a few years later by the Golden Lane to the south. In the 1930–40s the Poza Rica trend and the southern extension of the Golden Lane were discovered, followed by the offshore Golden Lane and Jurassic reservoirs in the 1950–60s. In the 1960–70s low permeability sands in Chicontepec were tested at the same time as similar rocks of the Spraberry Formation in the Midland Basin were beginning to be developed. As production started from oil shales in the USA, in 2010 Mexico began successfully evaluating the rich organic shales and marls of the Tithonian and Turonian. The Kimmeridgian and Oxfordian marls, rich in mature organic matter, also appear to have production potential.

From 1975 to 1982, following the discovery of oil in the Mesozoic of the Sureste Basin, oil production grew from 0.5 to 2.7 MMbopd and reserves increased from 6.3 to 72.5 Bboe. As a result of this success, the authorities decided that there were sufficient oil and gas reserves to sustain output for at least 25 years and reduced the NOC exploration budget from approximately US$2 billion in 1981 to $400 million by 2001, concentrating most of the resources in the Sureste Basin. Tampico-Misantla, where the fields were entering a mature stage, wells were less productive and producing oil from tight rocks was much more expensive, was all but abandoned and has had little further exploration.

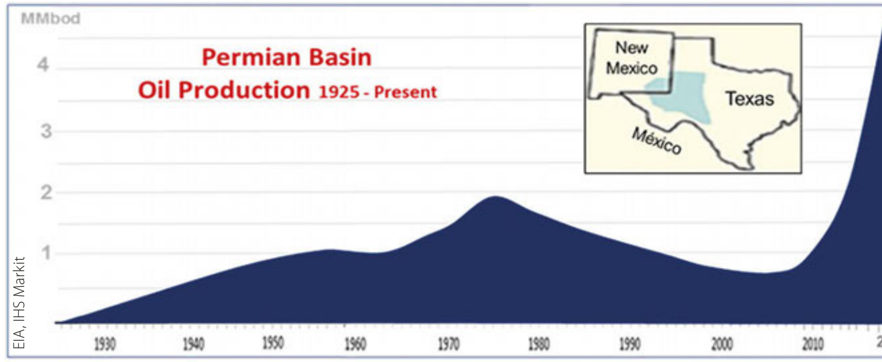


Figure 2: Rejuvenation of the oil production of the Permian Basin.

Times Change

Circumstances have changed, however. Today the Sureste Basin has few undeveloped reserves, no unconventional resources, and although there is good potential for yet-to-be-found reservoirs, these are elusive with new discoveries requiring expensive facilities. By comparison, the total resources in the Tampico-Misantla Basin are huge (Table 1), with unconventional in-place resources estimated to be over 100 Bboe and in similar reservoirs to those that allowed the Permian to multiply its oil output sixfold in less than ten years. Not only do the two basins have similar reservoirs but they also have similar resource volumes. These unconventional resources are in relatively shallow reservoirs and can be developed as economically as conventionals – faster, more easily and with less geologic risk.

Chicontepec Tight Oil Play

The richest and easiest resource to develop is the tight oil in the foredeep fill formed by the Sierra Madre uplift that was incised in the Late Palaeocene – Early Eocene by a long (120 km by 25 km) paleo-canyon named Chicontepec. A similar feature, the Bejuco-La Laja paleo-canyon formed in the north side of the Tuxpan Platform (Figure 1).

Earliest drilling in Chicontepec took place in 1926, but the wells had low productivity and there was little interest in their development, although a few isolated wells went into production in the 1940 and 1950s. In the late 1970s, interest was renewed by improved productivity and some scattered reservoirs were developed. Initial flow rates were highly variable and declined rapidly, so the wells needed to be fracture-stimulated to be able to flow or pump at commercial rates and were directionally drilled from central locations to minimise environmental impact and produced into centralised facilities. Oil gravities in the paleo-canyon vary from very light in the north (> 40° API) to very low in the south (10° API).

Between 40 and 90 wells a year were drilled in Chicontepec between 1973 and 1982, raising the output to over 12,000 bopd. In 1978 DeGolyer and Macnaughton certified the reserves, reporting that the paleo-canyon had 106 Bbo in place. All 29 fields were determined to belong to a single, contiguous giant oil field covering over 3,000 km² and at the time it was considered that over 16,000 wells would be needed to develop the field, with 11 Bboe being recoverable.

Table 1: Oil and gas resources of the Tampico-Misantla Basin. (National Hydrocarbon Commission)

Reservoir Type		Original in Place (B boe)	Cum. Prodn. (B boe)	3P Reserves (B boe)	Recovery Factor %
Carbonates	(Conventional)	35	7	1.6	20
Tight oil	(Unconventional)	65	0.3	6.3	0.4
Shale Oil	(Unconventional)	39	0	–	0
Yet to be found	(Conventional)	2	–	–	–
	Total	141	7.3	7.9	19.6

Production Crisis

Oil production in Mexico during this period was less than 0.5 MMbopd, insufficient for the country's needs, so Chicontepec appeared to be a solution, but just before the project was started the highly productive giant oil fields of the Sureste Basin were discovered, and all the available resources were dedicated to developing these. Over the next 30 years, small efforts were made to develop Chicontepec, and some of the reservoirs with better permeabilities came on stream despite their low productivity, including the Soledad-Coyotes, Miquetla, Agua Fría-Coapechaca-Tajín, and Presidente Alemán fields.

In the early 2000s a new attempt was made to fully develop these reservoirs. Their volumes were recertified by both DeGolyer and Macnaughton and Netherland and Sewel, who confirmed the order of magnitude of the volumes certified 30 years earlier. Better drilling and completion techniques were applied, such as commingling, larger hydraulic fractures, PDC bits, better subsurface models and more efficient facilities. This new effort was predicated on a certified resource base of 137.3 Bbo in place and 63 Tcfg and 17.1 Bboe of 3P reserves.

Output increased from a few thousand bopd to over 30,000 bopd over a short period and supported a 10-year

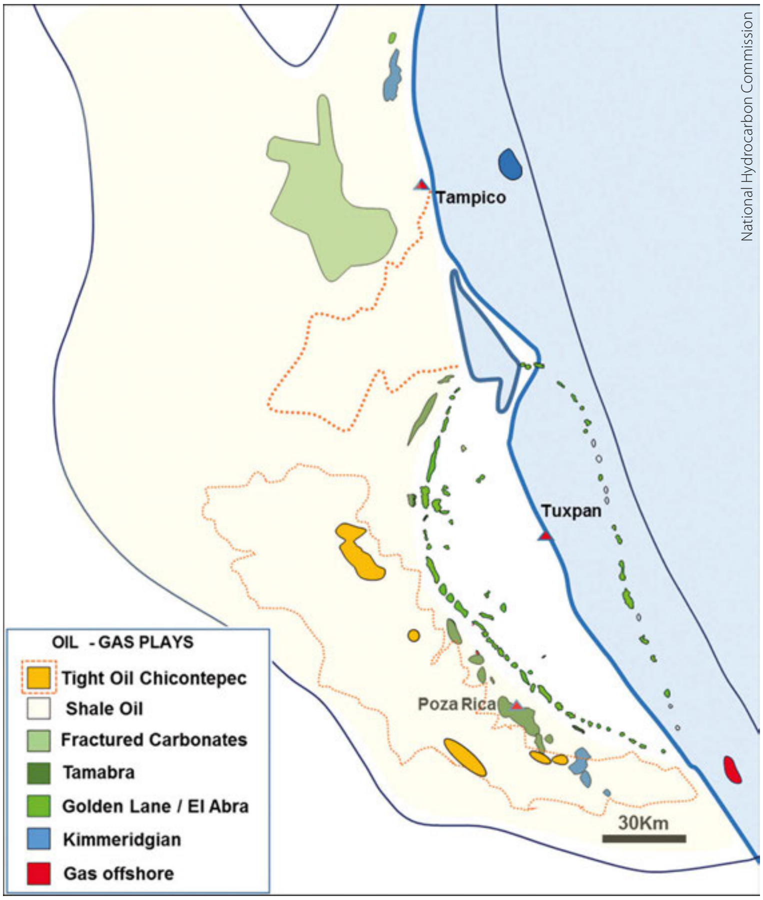


Figure 3: Legacy and unconventional plays of the Tampico-Misantla Basin.

plan that recommended an extensive drilling campaign to raise production to over 600,000 bopd. The Chicontepec Integral Project became very important as the offshore Cantarell field (2.2 MMbopd) had started declining (and with it, Mexico's oil production) and the only important undeveloped reserves that could replace the lost production were offshore Campeche in Ku-Maloob-Zaap with 10–12° API oil – and Chicontepec. The over $60.00/bo break-even cost and enormous CAPEX requirements remained a challenge, but at the time the oil price was soaring and, after a slow start, Chicontepec output increased to more than 70,000 bopd. But when the oil price collapsed in 2008, the government decided to suspend production.

Technology Opportunity

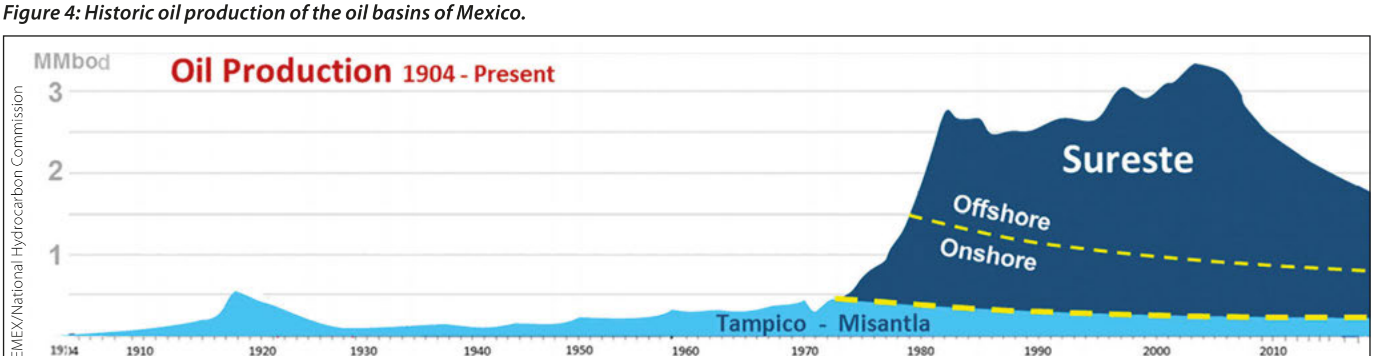
When the price started to recover and the technologies to extract oil from low permeability rocks at economic rates became a reality, a new attempt to develop Chicontepec was made, this time through what were termed Integral E&P Contracts (IEPCs). The objective of these was to incorporate new technologies, best practices and new investors, but since the Mexican Constitution at the time precluded third parties from participating directly in exploration and production, the contracts were awarded with the developments being designated as services. These contracts did not result in a significant increase in output, as the companies' incentives were in the services provided and not in increasing production or the reserves, and by 2012 the government was considering implementing an energy reform that would allow private participation in upstream projects. The authorities decided to outsource most of the Chicontepec development as new E&P profit/production-sharing contracts by 'migrating' the previous service IEPC's to this new contractual form once the reforms were implemented.

A new reserves certification conducted at the time downgraded the Chicontepec volumes so the official numbers by 2017 were 59 Bo and 31.5 Tcfg (in place) with 3P reserves of 6.3 Bboe (National Hydrocarbon Commission (CNH), 2017). The CNH (2020) official numbers are 65.35 Bboe but with only 4.6 Bboe of 3P reserves. Downgrading of these unconventional 3P resources at a time when most reserves in other basins are being revised upward is surprising, but it is possible that the new technologies and concepts that can render very tight, uneconomic, or marginal resources recoverable were not taken into consideration.

Since 2018 there has been a moratorium on outsourcing new projects and the use of hydraulic fracking and the IEPC contracts have not migrated, so the Chicontepec development has not been outsourced and with PEMEX operating only the small fields, the play is almost abandoned. In the meantime, the price of oil could sustain unconventional projects because operators have managed to reduce costs below break-even and they continue developing the Permian, the Bakken, the Eagle Ford, and others in the USA, and the Vaca Muerta in Argentina.

The original oil and gas volumes reported for all 29 fields, albeit downgraded, are still staggering. Less than 0.5% of the resources have been extracted: if only a small fraction of these oil and gas reserves

Figure 4: Historic oil production of the oil basins of Mexico.



Original Volume (2009)	3P Reserves (2009)	Original Volume (2016)	3P Reserves (2020)	Oil Cum. Prodn. (2020)	Gas Cum. Prodn. (2020)
(B boe)	(MM boe)	(B boe)	(MM boe)	(MM bbl)	(Bcf)
147.18	17,096.8	65.35	4,638.1	275.1	505.9

Table 2: Original volumes and 3P reserves for the Chicontepec fields (before and after downgrade) and 2020 cumulative production. (PEMEX/National Hydrocarbon Commission)

were produced, it would have a huge impact on the upstream industry and economics of Mexico (Table 2).

The Shale Oil Plays

In the last decade, the shales in several Mexican basins have been extensively studied and their oil and gas potential tested. There are several shale and marl units in the basin which are rich in mature organic matter, and three of them – the Turonian Agua Nueva, the Tithonian Pimienta and Oxfordian Santiago Formations – have oil and gas that can be produced. In addition, the Kimmeridgian Tamán Formation has source rock characteristics, although its potential to produce has yet to be fully evaluated. These shales are widely distributed in northern and eastern Mexico (Figure 5).

The Tithonian Pimienta Formation, present in most of the basin and in the southern Burgos Basin, appears to be the most prolific. Several authors have concluded that it has excellent characteristics for oil and gas generation based on its good total organic carbon (TOC) values, hydrogen indices, and vitrinite reflectance. The kerogen type, which is indicative of mature, oil prone, marine organic matter, and the fact that these formations are rich in carbonate content, indicates very good potential as an unconventional resource.

Jarvie and Maende (2016) present a compelling case for the Upper Jurassic in the Tampico-Misantla Basin and conclude that there is very high potential for unconventional shale oil production due to the large volumes of retained petroleum, favourable rock properties, maturity that favours liquids, and high net thickness. They estimate about one billion barrels per 12,000 acres (48.6 km2) in the Upper Jurassic and conclude that the Tampico-Misantla Basin is potentially one of the best in the world. They also consider that the total petroleum generation potential for the Tithonian in the basin is 840 bo per acre-foot (for shale at 1.00% vitrinite reflectance), better than the Eagle Ford, the Woodford and the Vaca Muerta shales, although not as good as the Bakken, or the Bazshenov shales in Russia.

In the Tampico-Misantla Basin the Tithonian shale has a widespread distribution, being absent only over the Tuxpan Platform, the Tamaulipas Arch and the Teziutlán High. Several studies have established the Tithonian shale to be in the oil window and to have 1–8% TOC, kerogen type II/III and low ▶

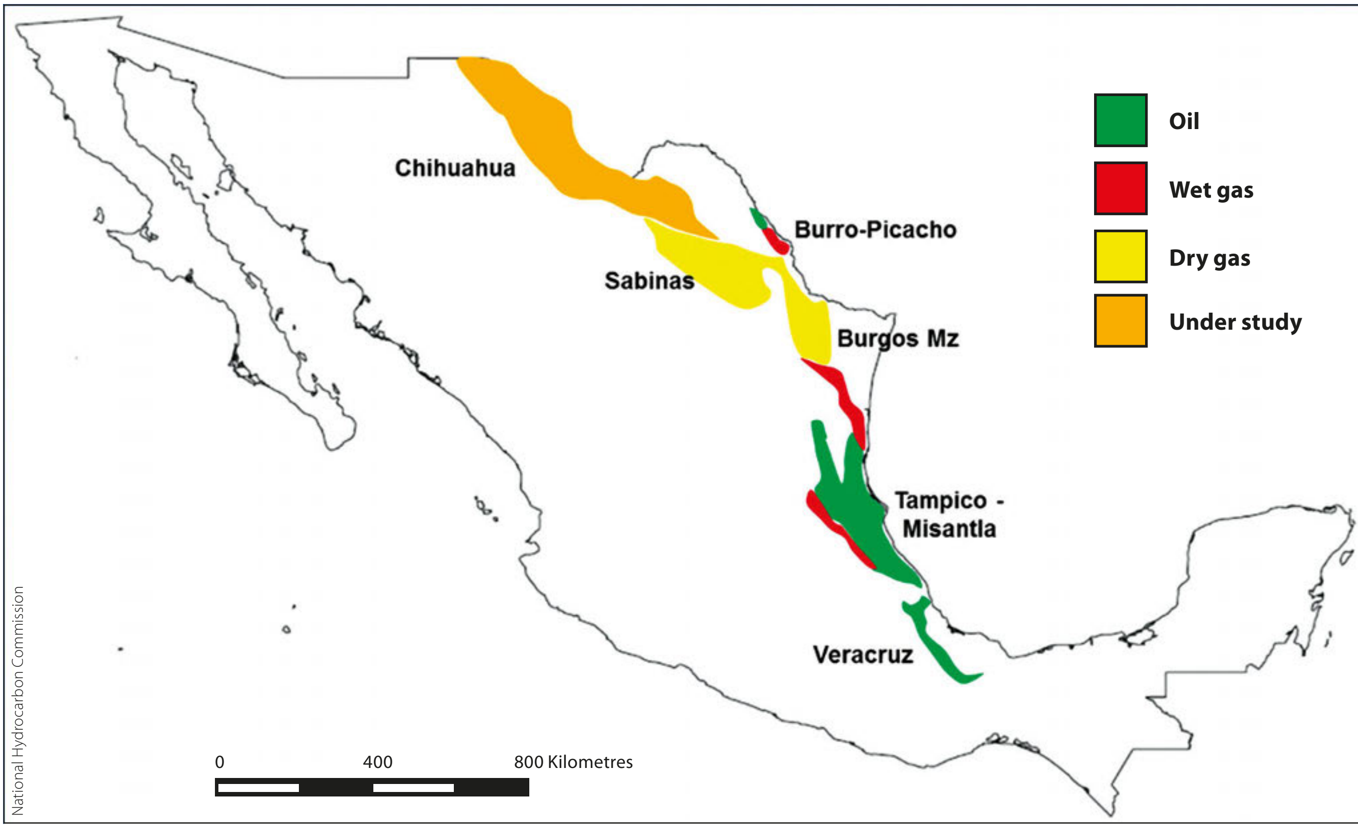


Figure 5: Distribution of oil and gas in shales in Mexico.

Table 3: Oil and gas potential of the Tampico-Misantla Basin shales. (National Hydrocarbon Commission)

	Oil (Bo)	Wet Gas (Tcf)
Turonian Agua Nueva	13.0	7.6
Tithonian Pimienta	17.8	13.1
Oxfordian Santiago	4.0	–
Total	34.8	20.7

structural complexity. The Turonian marls have 0.5–8% TOC, type II kerogen and are in the oil and gas windows.

Recent studies of the Pimienta Formation in the Tampico-Misantla Basin address its petrology, mineralogy, geochemistry, petrophysics, resources and production potential. To date these resources remain untapped despite the very significant recoverable reserves identified (Table 3).

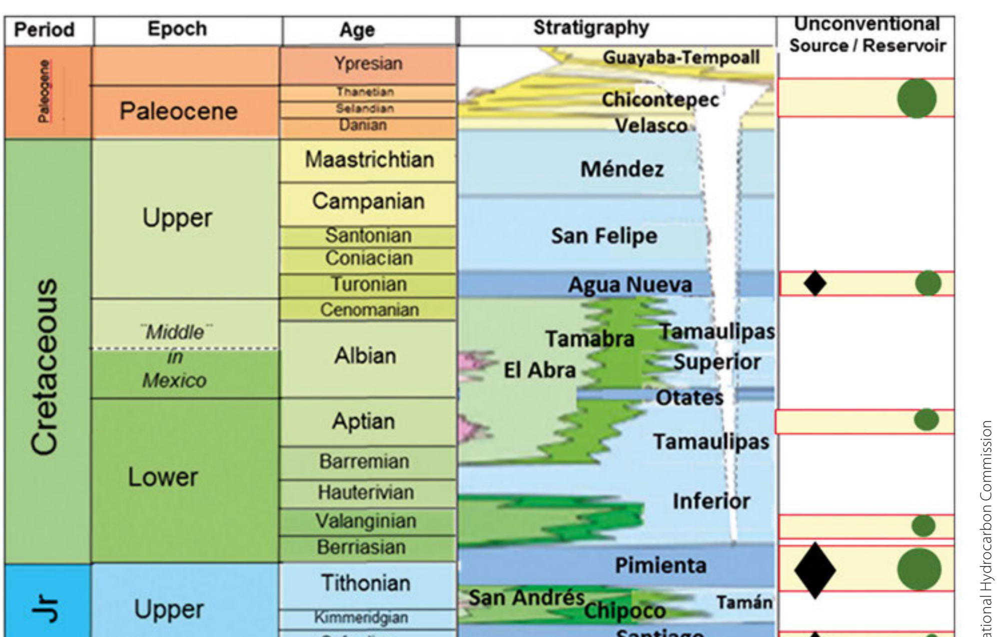


Figure 6: Stratigraphic column showing distribution of the major reservoirs and oil and gas in shales in Mexico.

Untapped Potential

Development of the unconventional resources of the Tampico-Misantla Basin together with the exploration of the basin with new concepts and technologies and the optimisation of its legacy reservoirs, could put Mexico back on the list of the top oil-producing nations. The Tampico-Misantla Basin has the oil and gas resources and conditions required to be a super basin. It has the necessary infrastructure, access to markets and field services providers. It could be rejuvenated just as the Permian Basin was, thanks to its huge tight oil shale potential and its lack of exploration over recent decades.

References available online. ■

GeoStreamer X Delivers Near-field Multi-Azimuth Dataset for Accurate Lead Characterisation, South Viking Graben, Norway

PGS has recently acquired and processed an innovative multi-azimuth multisensor survey in the prolific South Viking Graben, Norway. The dataset delivers reliable attributes for accurate reservoir characterisation. This area has provided numerous successes in multiple plays over the past decade and more recently the focus is on potential near-field opportunities.

This quantitative interpretation project examines the various Tertiary to Permian reservoir levels using GeoStreamer X data combined with many wells present in and around the area of interest. For the latter, an interactive rock physics modelling product (PGS rockAVO) has been used, enabling a rapid assessment of the elastic property variation as well as the prestack seismic response to changes in reservoir properties (such as, porosity, saturation and volume of clay).

By integrating this new dataset with regional well information, many of the exploration and near-field exploration challenges can be addressed. The evaluation of reservoirs and trapping styles of existing fields and discoveries is now possible with this unique dataset and additional opportunities can be revealed.

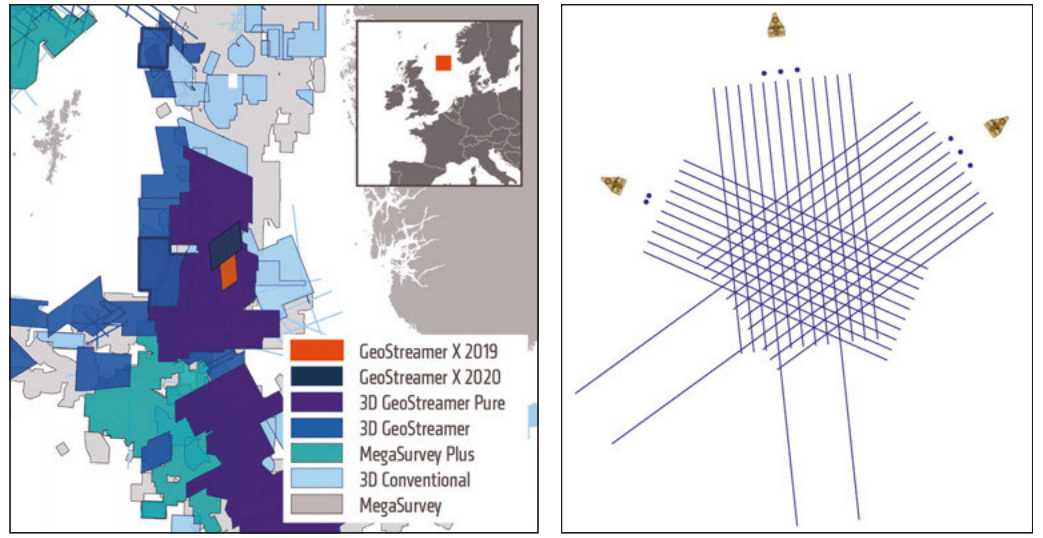


Figure 2: The GeoStreamer X Viking Graben location (left) and acquisition configurations (right). Two new azimuths were acquired in 2019 in addition to the 2011 survey; the new azimuths are indicated by the two extended streamer tails.

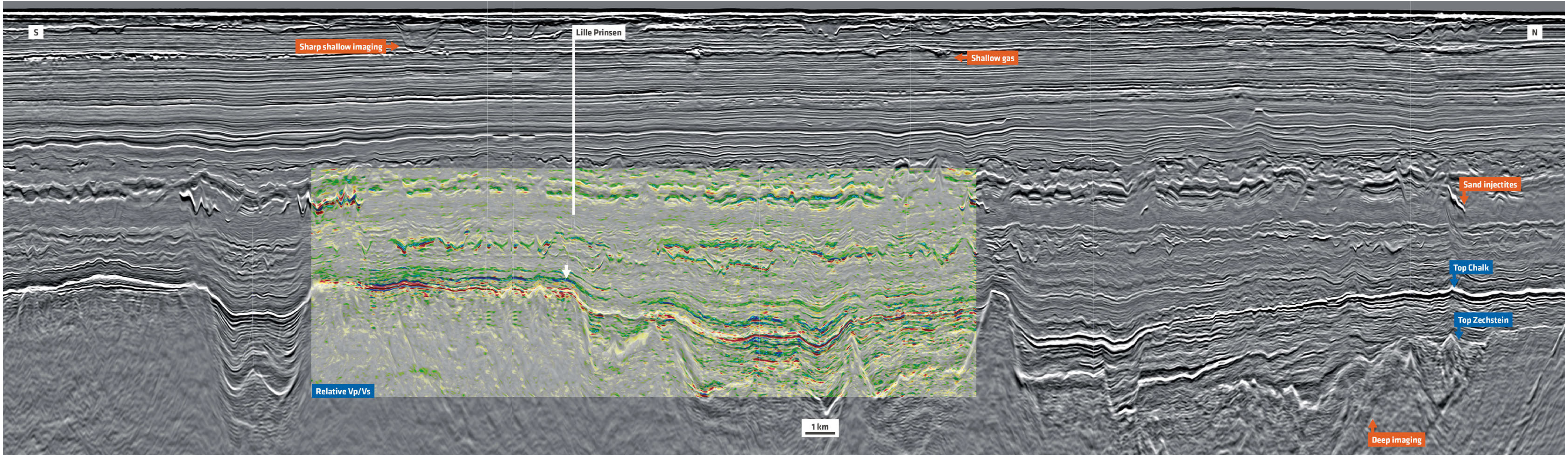


Figure 1: This full stack GeoStreamer X PSDM line runs through the main discoveries and fields in the South Viking Graben. In addition to the seismic display (in grey colour scale) a relative Vp/Vs section is overlaid. This attribute has been extracted from all azimuths and from the isotropic gradient and intercept estimation. The relative Vp/Vs highlights some key discoveries in the area such as Verdandi and Lille Prinsen in the Tertiary, characterised by a low Vp/Vs (blue colour), and Hanz, in a more downdip situation encountering hydrocarbons in the Upper Jurassic level. Additionally, this elastic attribute overlay highlights both the injectites and the so-called V-brights in the Grid formation extremely well.

Multi-Azimuth, Multisensor, Quantitative Interpretation Case Study: South Viking Graben, Norway

GeoStreamer X is a broadband multi-azimuth acquisition and state-of-the-art depth-imaging solution. Here we demonstrate the suitability of the dataset for reservoir characterisation by delineating near-field exploration opportunities and providing better reservoir understanding.

CYRILLE REISER and ERIC MUELLER; PGS

The case study area is from the South Viking Graben, offshore Norway. Major fields are situated in this area, comprising several stratigraphic intervals (Figure 3): Eocene – Balder sands, Palaeocene – Heimdal sands (Grane, Jacob, Svalin, North and South and Verdandi), Upper Jurassic – Draupne (Jacob Sør and Hanz field), Late Cretaceous – Chalk Tor formation (Ragnarrock), Late Triassic to Mid-Jurassic (Ivar Aasen), Late Triassic to Early Cretaceous sandstone (Edvarg Grieg), Upper Jurassic intra-Draupne sandstone (Johan Sverdrup). More recent discoveries include the Lille Prinsen, drilled in 2018, which encountered various hydrocarbon intervals in the Eocene (Grid sand), Palaeocene (Heimdal sand) and Permian (Zechstein Group).

The GeoStreamer X multi-azimuth (MAZ), multisensor acquisition was designed to overcome diverse and complex imaging challenges. In 2019 two new azimuths were acquired using a 12 × 6 km × 85m high-density GeoStreamer spread, including two 10 km-long streamers for improved Full Waveform Inversion (FWI), and a wide-towed triple source configuration (225m separation between the outer source arrays) to deliver reliable near-offset coverage in the 50–125m offset range. This seismic survey provides richer azimuth/offset information and illumination below and above the intervals of interest. These two additional azimuths are complementary to the existing reprocessed narrow-azimuth multi-client broadband GeoStreamer survey acquired in 2011 and together provide an azimuthally diverse dataset.

Multi-Azimuth Imaging in a Nutshell

The multi-azimuth dataset was subjected to a complex and rigorous prestack depth migration sequence with the main processing steps summarised below:

- Comprehensive demultiple sequence addressing the short and long period multiples integrating 3D convolutional and wave equation SRME (Surface Related Multiple Elimination) and SWIM (Separated Wavefield Imaging)
- Full Waveform Inversion based on refraction information up to 12 Hz from 0 to 10 km, and reflection FWI up to 15 Hz from 0 to 6 km offset
- As the azimuth distribution and offset diversity is rich up to 2 km offset, and up to 40 degrees of incidence angle down to the chalk interval, 30 degrees azimuthal sectors have been generated for this survey. All these datasets were regularised and migrated as a single five-dimensional volume.

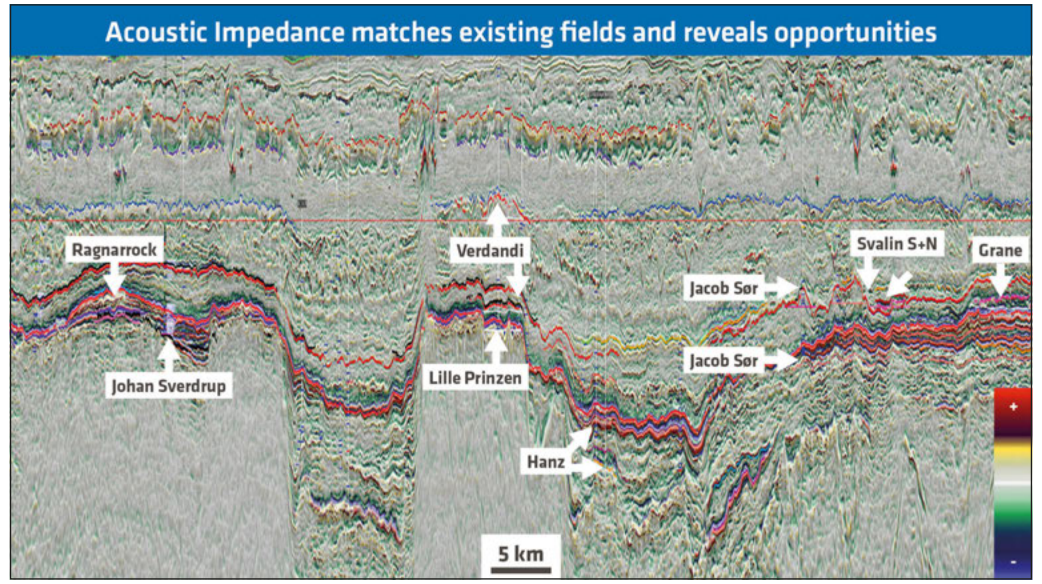


Figure 3: Regional full stack GeoStreamer X relative acoustic impedance random line going through the main fields, recent discoveries and their respective stratigraphic age where a hydrocarbon interval has been encountered. The section also illustrates many features which degrade subsurface imaging such as injectites and the irregular, high impedance Chalk.

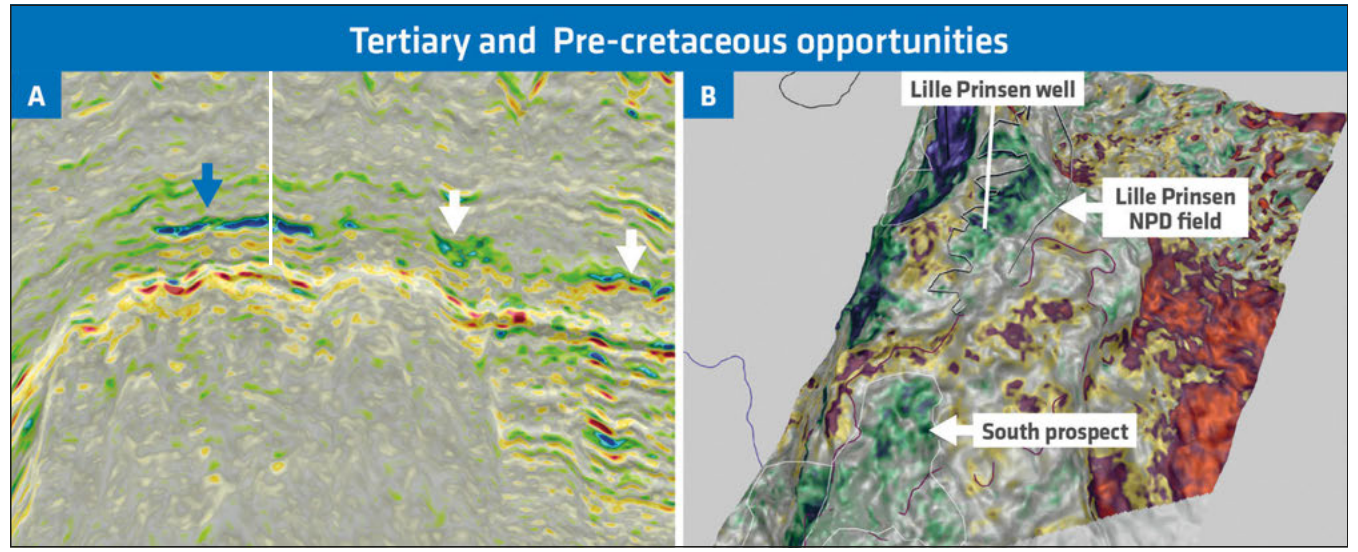


Figure 4a: Relative isotropic gradient impedance using multi-azimuths and conditioned angle stacks. Some clear improvements (marked with the blue arrow) can be observed at the Heimdal gas sands level and low impedance responses downdip of the main structure (white arrows) were not visible previously and could indicate the presence of oil accumulation.

Figure 4b: Ultra-far relative impedance map extraction is well correlated to Vp/Vs at the top Cretaceous over an 8 ms window. Blue-green anomalies match very nicely with the Norwegian Petroleum Directorate (NPD) outline for the Lille Prinsen discovery at this level. A visible anomaly to the north-west was tested successfully by a recent appraisal well. Additional opportunities exist to the south of Lille Prinsen as well as down-flank.

Latest Seismic and Quantitative Interpretation Reveals New Insight

Seismic interpretation has been conducted over the whole area based on this multi-azimuth broadband seismic and calibrated with 11 available wells. A regional interactive rock physics modelling product was further developed (PGS rockAVO) and used to better understand the elastic properties response to changes of the reservoir properties (e.g., VClay, Porosity) over the various intervals of interest.

The expected AVA responses for the main reservoirs are: Class II/IIp AVO for the Tertiary Heimdal sands with hydrocarbons (Lille Prinsen, 16/1-29S), and Class I/II for the Upper Jurassic Draupne sands (Hanz, 25/10-8) and for the Permian Zechstein carbonate over Lille Prinsen side-track (16/1-29ST2). For the Heimdal sands in particular, the reservoir presents the following elastic properties characteristics: very weak acoustic impedance and strong Vp/Vs response rendering-in-effect. This reservoir is almost invisible on the near-angle stack but visible on the far and ultra-far angle stack, requiring accurate prestack processing and conditioning to preserve the Class II/IIp response in presence of hydrocarbons. The prospect definition is extremely challenging without a detailed AVO understanding and careful processing. The AVA responses were later confirmed by the well-to-seismic tie.

Additionally, Reservoir Oriented Processing (ResOP) was performed using all azimuthal sectors (6) and angle stacks (4) with the focus on the main reservoirs and including: spectral harmonisation, de-noise, low frequency enhancement, multi-angle-azimuth time misalignment correction and the estimation of the isotropic / anisotropic gradient and intercept. One of the main outcomes of this targeted seismic data conditioning has been a distinctive broadband wavelet (3Hz to 80Hz bandwidth in the Eocene/Palaeocene interval) with very low side-lobe energy and presenting all the broadband wavelet characteristics (prestack and per azimuth).

The seismic quality provides excellent well-to-seismic ties in all azimuths and associated angle stack directions. The statistics show an average cross-correlation of 80–85% in all azimuthal/angle directions for 10 wells. The AVO class observed at the various reservoir levels from the wells have all been confirmed.

The GeoStreamer X data quality has enabled the resolution of substantially more stable gradient impedance (Figure 4a) and now provides a clean, and continuous interpretation at the Heimdal sand level, accurately delineating the anomalies and opening-up additional near-field exploration opportunities (white arrows). The well track represented is the Lille Prinsen gas discovery at the Heimdal level (blue arrow).

This multi-azimuth multisensor quantitative interpretation provides very interesting results for the deeper reservoirs. Few additional wells have been drilled following the Lille Prinsen discovery to examine the potential in the deeper stratigraphic intervals such as Jurassic sandstones and the Permian. Based on the elastic attribute extraction and the pre-Cretaceous interpretation (Figure 4b) there are some clear indicators of hydrocarbon presence at the Upper Jurassic and Zechstein level. These anomalies are of reasonable size and could represent interesting near-field exploration potential.

Near-field Opportunities Revealed with GeoStreamer X Dataset

It has been demonstrated how an innovative acquisition set-up with a wide-towed source, azimuth diverse broadband seismic dataset has overcome the main exploration challenges in the prolific Southern Viking Graben and delivered a significantly improved understanding and opportunities suitable for near-field exploration have been mapped using an integrated quantitative interpretation workflow. ■

Wild Roving with Percy

Geology is the key in this search for life.

NEIL HODGSON*, KARYNA RODRIGUEZ* and IAIN BROWN
*Searcher, UK.

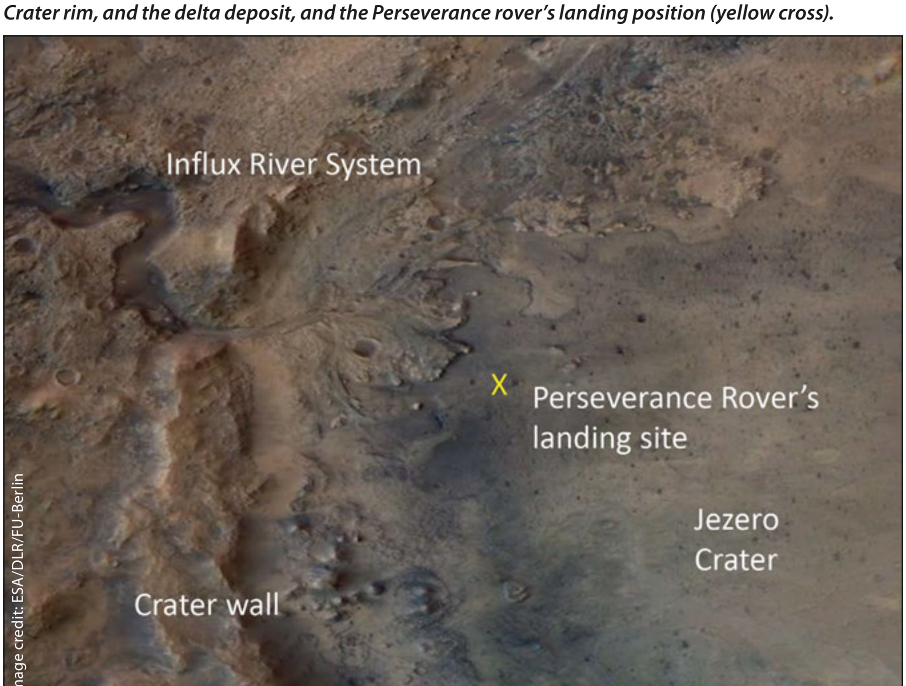
There is a wonderful urban myth that in 1877 when Giovanni Schiaparelli used 'Canali' in his native Italian to describe linear features on the surface of Mars, the mistranslation of this into English gave birth to the idea of manufactured water courses on our red and fiery planetary neighbour. Actually, nothing was lost or found in his translation, as the hazy optics of telescopes available at the end of the 19th century had led many astronomers to report 'canals' on Mars, breathing fevered life into two new genres of literature: Sci-Fi (H.G. Wells's 1897 *War of the Worlds*) and space-fantasy (Edgar Rice Burroughs's 1911 *John Carter of Mars*).

Fantasy to Facts

Space science is only as good as the data you collect and improvements in optical telescopes soon allowed the concept of canals or rivers, and even free water on Mars to be debunked. Yet after 140 years of remote imaging improvements, some of this needs to be reconsidered. A high-resolution satellite (HiRise) in orbit around Mars has revealed details of many dendritic drainage systems and from the discoveries of a suite of remote-operated vehicles on the surface, we now know the surface of Mars was indeed shaped by water flowing naturally in rivers and lakes 3.5–4 billion years ago, (Ga).

Today, Mars is as cold as central Antarctica. The forces of geology on Mars are alien to terrestrial geologists where plate tectonics, gravity and water (both ice and rain) are the architects of our geography. For over three billion years the surface of Mars has only been sculpted by the gentle winds of a thin atmosphere, volcanism and meteorite impacts. It is a chilly red planet that sits on average 220 million km from the Earth and there is still a lot we do not fully understand about its history – the mysterious chaotic terranes (Meresse et al., 2008) and the fields of Martian 'spiders' at the poles (Piqueux et al., 2003). Yet perhaps the biggest unanswered question, one with existential consequence for us all, is whether life once arose independently on Mars.

Figure 1: Image showing the fluvial system flowing from the left (north) through a break in the Jezero Crater rim, and the delta deposit, and the Perseverance rover's landing position (yellow cross).



As we write this, history is being made as the second robotic geologist to put wheels on Mars, a small car-sized rover called Perseverance (Percy), has set off on a new adventure: the search for signs of ancient life in and around the 45 km-wide Jezero impact crater (Croatian for 'Lake'). Percy is the latest evolution of a series of Martian rovers, namely Spirit, Opportunity, and the Mars Science Laboratory Curiosity. Curiosity landed in Gale Crater in 2012 with the job of looking at outcrop and at hand-specimen-scale rocks for signs of ancient water. In over 3,000 'sols' (Martian days) since landing, it has travelled 25 km exploring for signs that Gale Crater was habitable in the past. Nuclear-powered like Percy (Plutonium 238 and a thermocouple), Curiosity has fantastic technology on board including an X-ray fluorescence analyser and has undertaken some great science on its nine-year exploration. However, its greatest success and impact is arguably from the hi-resolution images it has sent back. Hundreds of images show geology laid down in high-energy rivers and flash floods, pools and small lakes. So, eons ago there was water and plenty of it. What Curiosity's successor is going to do, is to search in a depositional environment that may have been conducive to supporting aquatic organisms and potentially life as we know it.

An Amazing Journey

The technical challenge of successfully landing a probe on Mars is difficult enough but having it function afterwards is frankly miraculous. Percy had a 7 month, 480 million km trip, at speeds of 40,000 km/hr. Nasa has engineered an incredible system to land a rover on Mars in one piece, by attaching a personal 'jet pack' to Percy to slow it down as it approaches the surface and then lowering the rover to the ground on detachable cables (Figure 2). At the

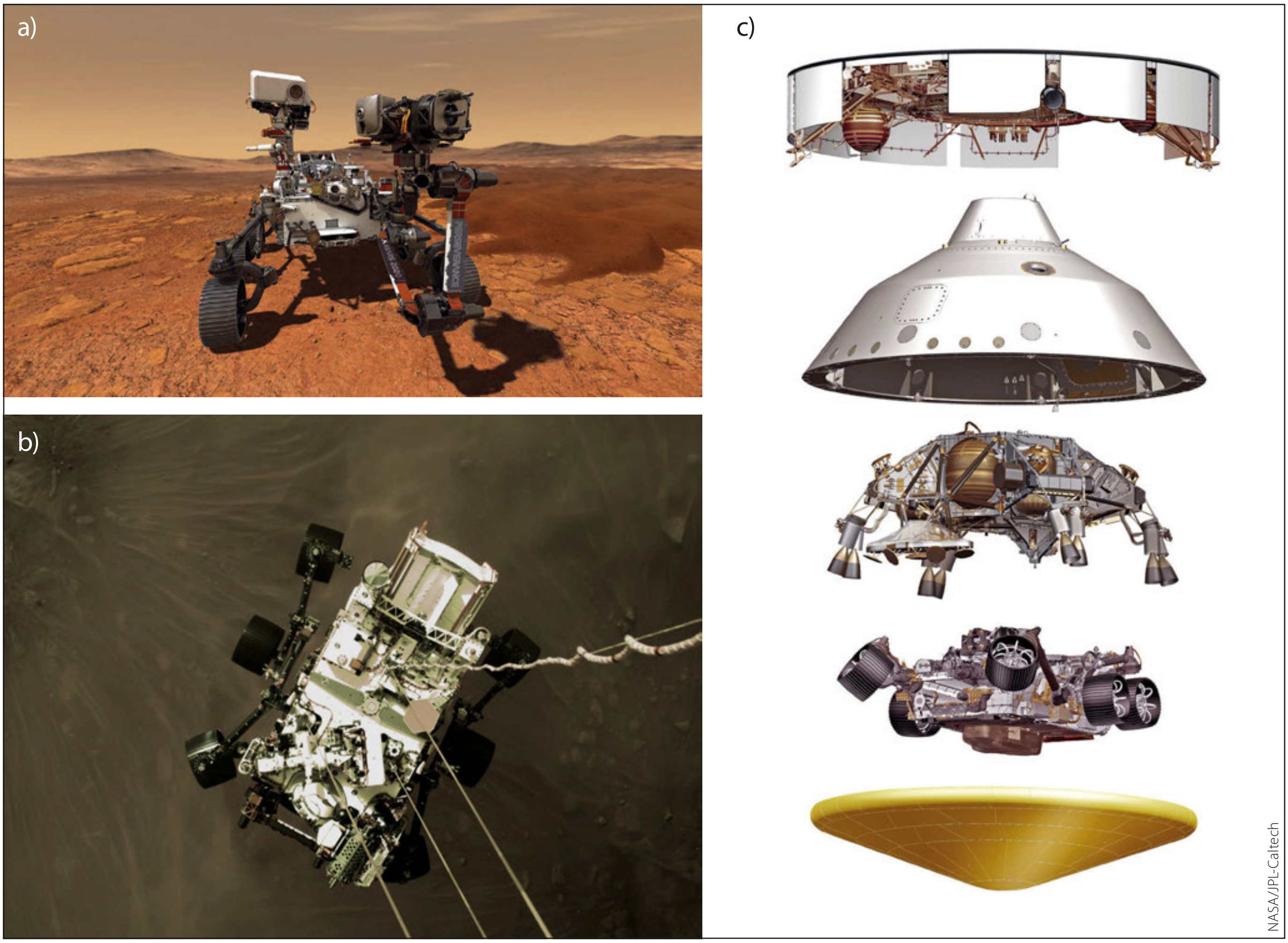


Figure 2: a) Artist impression of Perseverance on Mars. b) Perseverance rover being lowered to Mars'2 surface. c) The five major components of the Mars 2020 spacecraft. Top to bottom: cruise stage, back-shell, descent stage, Perseverance rover and heatshield.

end of its extraordinary voyage, Percy was deployed gently to the Martian surface, an incredible 3m away from the intended landing site. If this were a Hollywood movie you might be impressed, but this is real life technology which is frankly amazing. Shortly after landing Percy dropped off its passenger – a small robotic Ingenuity reconnaissance helicopter, which has now successfully completed three flights – the first powered controlled flight using atmospheric lift on another world. The small coaxial, drone rotorcraft is serving as a technology demonstrator for the potential use of flying probes on other worlds and will have the potential to scout locations of interest and support the future planning of driving routes for Mars rovers. Its flights will be telerobotically planned and scripted by operators at the Jet Propulsion Laboratory.

Terrestrial Sedimentology, Mirrored on Mars?

The Jezero Crater where Percy has landed is a late Noachian crater formed by a meteorite impact (or bolide, 3.8 Ga). Most of the floor is a fairly flat layer of volcanic ash-fall tuff deposited in the first 100 million yrs after the 'bolision' and is scattered with boulders from crater wall collapse and other later bolide impacts. Volcanism on Olympus Mons (the largest volcano on Mars and indeed in the solar system) started around this time and has continued episodically to almost the present day. The volcanic ash in the Jezero Crater is mostly basaltic, but some of this material has altered to magnesium carbonate and serpentinite via a process of hydration. Identifying this transformation from an orbiting satellite gave a hint to the main actor in the geodrama of the crater. Indeed, on the north-west and west-side of the Jezero Crater is the most extraordinary, raised feature, which suggests how this hydration occurred.

Beyond Jezero's north-west crater wall, on HiRise satellite images, there is a sinuous and dendritic channel feature that approaches a breach in the outer rim and leads to what appears to be a large fluvio-lacustrine delta of Late Noachian Age (3.7 Ga) (Figure 1). Here, a series of apparently prograding point bars have migrated out into the crater, when it was full of water, then sequentially avulsed to build a delta fan morphology (Figures 1 and 3). Multiple fluvial channels cross the delta top to an abrupt edge, were the delta has been eroded during the subsequent draining of the Jezero Crater (Figure 4). The depth of the water column in the lake at a given time and chemistry of the water will be deducible from images of outcrop (the sequence stratigraphy of the prograding delta) and science experiments undertaken by Percy in the next few months. Currently Percy is sitting just basinward of the

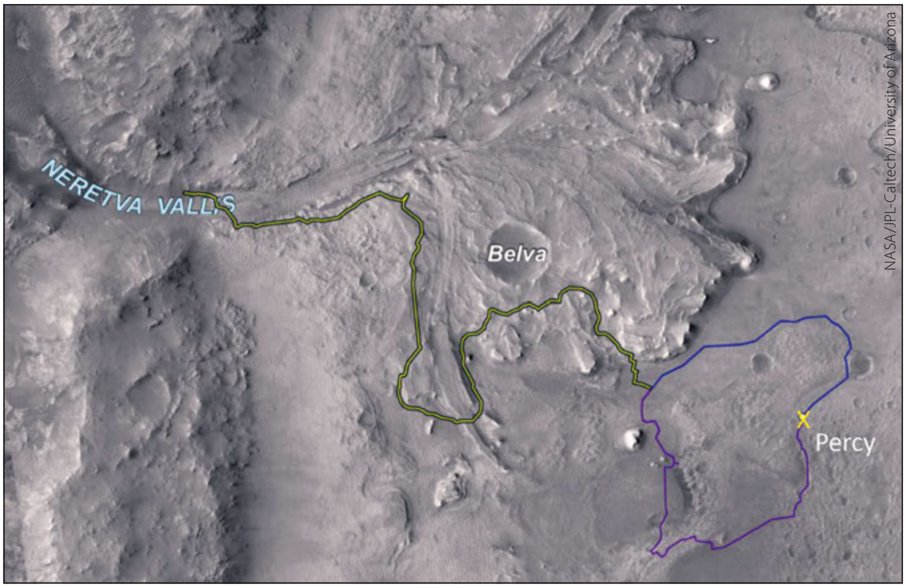


Figure 3: Close-up of the delta. Percy has two possible routes to reach the delta front (blue or purple) which will allow him to avoid some rough, soft dunes and boulders terrain. Yellow line is the anticipated path of Percy on to the Jezero Delta and into the feeder channel called 'Neretva Vallis'.

prograding clastic delta, on the hydrated volcanic sediments that would have once been the lake bottom.

More Iceland than Idaho

An obvious question might be what was the climate like on Mars when water was flowing? The Curiosity rover did some X-ray powder diffraction (XRD) on phylosilicates and NASA geoscientists then matched them to different environments on earth and came up with a 'more Iceland than Idaho' correlation.

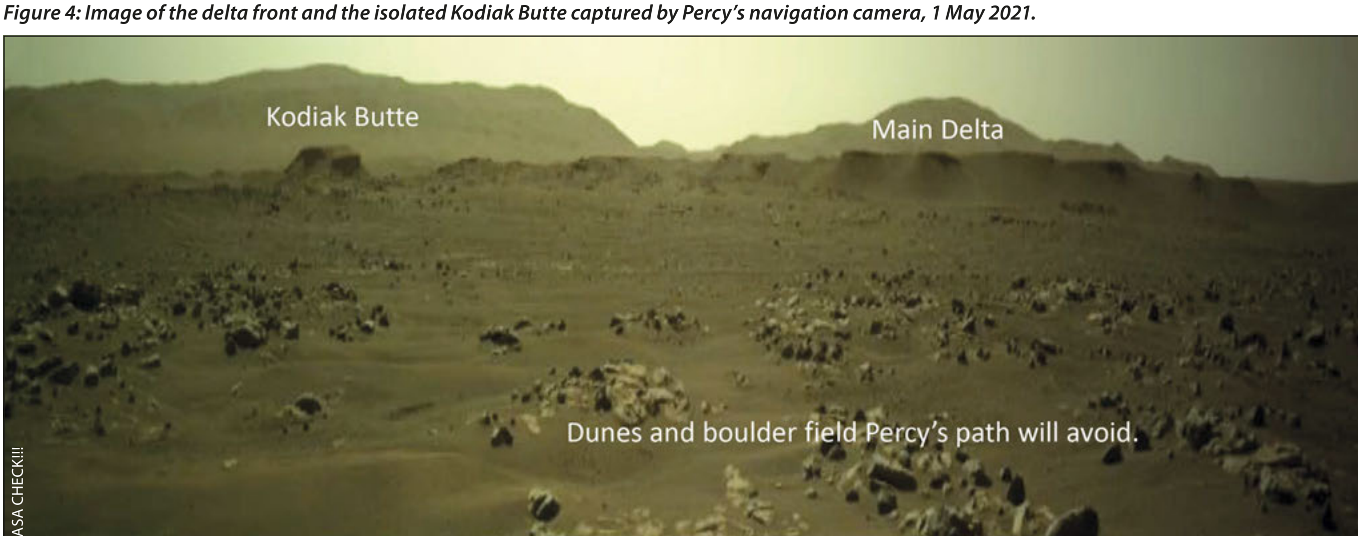
At some point in Mars's history, some 3.2 to 3.0 Ga ago, free water no longer flowed on Mars and the lake dried out. The basinward edge of the delta is today, a very steep set of cliffs or bluffs. Partly eroded by the low-stand of the lake drying up, and with no free-water to remove eroded materials, these bluffs have since been cut back solely by the wind of Mars's thin atmosphere. Blowing gently but for 3.5 Ga, these winds have preferentially removed mudstone flakes leaving the coarser sand 'skeleton' of the delta behind. The first images to be sent back show large cliffs on this isolated hill (or 'butte') in the crater, where 30–40m vertical outcrops sit above alluvial-type scree deposits (Figures 4 and 5). This butte, named 'Kodiak', is 52m high and 2.5 km from Percy. The spectacular cross-bedded unit is 10–15m thick. The lower units in these sequences would have been deposited on the lake bottom and present a logical place to look for organic-rich materials (the Curiosity rover has already detected organic chemicals in a core in the Gale Crater), which deposited on the lake floor or formed mats at the lacustrine crater rim.

Remote Sample Delivery

Mars's lack of a convecting mantle means that unlike Earth, it has an insufficient magnetic field to deflect the solar wind, allowing the atmosphere to be progressively stripped over the last four Ga. But at the time of the formation of the Jezero Crater Delta, conditions on Earth may not have been too dissimilar from Mars. 3.7 billion years ago on Earth, the first signs of multicellular life, cyano-bacteria, were emerging, and leaving traces as stromatolites. Such ancient rocks are not that common on the turbulent plates of the erosive water-bearing Earth, but on Mars they are widespread and pristine. The challenge for Percy is to find signs in these old rock sections that as life was gaining a toehold on Earth, the same was occurring on Mars.

On its journey over the next several years Percy will be looking for stromatolite-textured rock formations, organic-rich horizons, and textures that may represent algal mats at the edge of the Jezero lake (although these didn't develop on Earth until the Mesoproterozic) using its arsenal of on-board technology. On the mobile

Figure 4: Image of the delta front and the isolated Kodiak Butte captured by Percy's navigation camera, 1 May 2021.



laboratory are an array of equipment including PIXL (X-ray fluorescence Lithochemistry), SHERLOC (Raman and Luminescence for analysing Organic Chemicals) and a drill to take rock cores from the outcrops. Curiosity has drilled cores too, but Percy's cores will be stored with an audacious ambition. In a few years' time, Nasa plans to send another probe to Mars to meet up with Percy, pick up the collected regolith rock cores, and blast them into low Mars orbit where another craft will catch them and with an 'Amazon-like delivery' send them back to Earth. Percy is the first step in what is termed the Mars Sample Return in which about 35 samples, each weighing around 15 grams will eventually be sent to Earth. This will arguably be mankind's most complex and astonishing practical achievement if Nasa brings it off.

If successful with its exploration for signs of life, Percy will prove that life did not just arise on Earth, and that life can spark on other planets, even those of very different size, chemistry and environment.
If life has arisen independently on Mars nearly four billion years ago, then for a brief moment, we weren't alone in our solar system. Perhaps then, even the most hardened sceptic might admit the high probability of other life, and perhaps even geologists, elsewhere in the universe.

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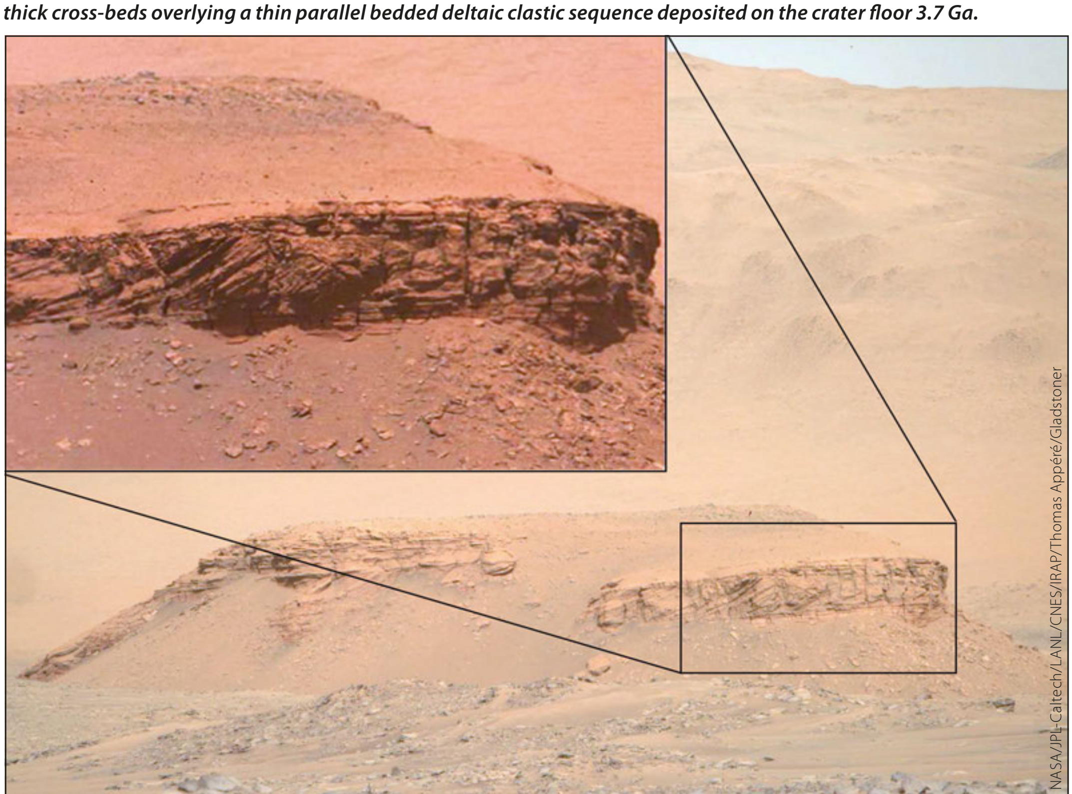
Figure 5: Detail of the Kodiak Butte with enhanced imagery. This is 52m high and 2.5 km from Percy. This outlier shows thick cross-beds overlying a thin parallel bedded deltaic clastic sequence deposited on the crater floor 3.7 Ga.



A Difficult Transition

The transition to cleaner energy sources poses a challenge to many NOCs.

JANE WHALEY

In the last edition of *GEO ExPro*, we discussed how the supermajor E&P companies are approaching the energy transition. The largest oil companies in the world by revenue, however, are state-owned national oil companies (NOCs), responsible for 50% of liquids and 48% of gas produced in 2021 (Wood Mackenzie), so their approach to the issue is of global importance. Many of these companies hold huge portfolios of assets, manage complex projects, employ millions of people to undertake a range of public services, and are often the major cash generator for their country. In fact, it is thought that more than 25 countries are dependent on their state oil companies for at least 20% of their total income, with some relying on oil revenues for as much as 90%. The slump in oil prices and demand as a result of Covid-19 has caused further problems for many NOCs, which are still expected to provide revenues for their governments, while the global movement away from hydrocarbons is putting them under further pressure.

NOCs rarely share information and data in the way that publicly-traded companies do, so it is hard to ascertain their likely strategies with regard to energy transition. In fact, only a few have formally set net zero targets, with a number of others announcing shorter term goals, while many are actively seeking to increase their production, against the trend of the international oil companies.

Net Zero Targets

Sinopec, the world's highest revenue-producing state-owned oil company, has announced plans to reach net zero carbon by 2050 by introducing low carbon methods in its refining processes and using renewables to produce green hydrogen. It also aims to become China's largest hydrogen company and will build 1,000 hydrogen gas vehicle refuelling stations over the next five years. The company says it will reduce its methane emissions from oil and gas production by 50% by 2025 and has started a pilot programme to build a carbon capture, utilisation and storage (CCUS) base in eastern China, using the captured CO_2 for enhanced oil recovery (EOR) in nearby fields. It has also planted over a million trees to help offset emissions.

Similarly, China National Petroleum Corporation (CNPC), China's largest energy producer, has announced a target of net zero CO_2 emissions by 2050, having pledged to spend about $1.5 billion annually in the next two years on renewable energy and hydrogen projects. Much of CNPC's push to carbon neutrality will be through investments in wind, solar, geothermal and hydrogen, but it is also expected to use intensive carbon offsetting schemes. In addition, it plans to prioritise exploration and production of natural gas, although it will still maintain the current level of oil production.

Malaysian state oil company PETRONAS has also announced a 'net zero by 2050' target. It aims to do this through reducing flaring and by mitigating emissions from operations through energy efficiency improvement and the use of low carbon or renewable energy and CCS, minimising waste and promoting recycling. Its shorter-term target is to reduce greenhouse gas emissions by 49.5 million mt CO_2 equivalent by 2024, supported by increasing its renewable energy capacity and carbon offsetting.

Aerial view of the huge greenhouses protecting the steam-generating mirrors at PDO's Miraah EOR project in Oman: an example of an NOC using renewable energy sources to reduce its emissions due to E&P operations.


GlassPoint

Commitments to Low Carbon

The secrecy that surrounds the plans of many NOCs does not mean that they are ignoring the energy transition. Even without announcing carbon neutral targets, many are actively expanding their portfolios into renewables, while keeping their focus on their core oil and gas projects. Petroleum Development Oman (PDO), for example, is building a 100 MW solar photo voltaic plant to power all the company's interior oil and gas operations, and the Abu Dhabi NOC ADNOC has formed a joint venture with a local renewable energy company to develop commercial-scale projects for CCUS, including a project with Emirates Steel Industries which will use and sequester 800,000 tonnes of CO_2 each year.

Russia is believed to have the world's largest reserves of natural gas and is the largest exporter of the commodity, so unsurprisingly Russian companies are concentrating on the role of gas as a bridge to a low-carbon economy. State-controlled corporation Gazprom, the largest gas producer in the world, has not announced any zero carbon targets, but is pushing technological hybrid solutions such as methane-hydrogen fuel in energy and transport to help reduce emissions. The Russian state-controlled oil company, Rosneft, announced objectives under its low-carbon agenda to 2035 that will prevent greenhouse gas emissions of 20 million mt in CO_2 equivalent and help it achieve net carbon neutrality.

Giant Brazilian NOC Petrobras has published six commitments related to the transition to low carbon with a goal of zero emissions growth by 2025. In 2020, however, the company announced that it would be at least two years before it moved into the renewables arena, prioritising instead its existing assets.

Last Man Standing?

With the largest daily oil production of any company, Saudi Aramco has for many years been one of the world's major global oil suppliers. It is vital to Saudi Arabia's existence, since the oil and gas sector accounted for about 50% of the country's GDP and 70% of its export income (2018).

Saudi Aramco has been implementing emission control measures for a number of years. It installed flare-gas recovery systems as long ago as 1980, powers some fields through renewable energy and has developed research programmes looking at reducing the carbon footprint of oil production, growing non-fuel applications for crude oil and advancing sustainable transport. However, the company emphasises the importance of the circular carbon economy, focusing on reducing emissions through energy efficiency technologies and the extensive use of greenhouse gases in EOR and for manufacturing industrial products and feedstocks. It is also actively removing CO_2 from the atmosphere through carbon sequestration initiatives, including planting millions of trees to combat desertification and enhance biodiversity.

Saudi Aramco is actively removing CO_2 from the atmosphere by restoring mangrove habitats in Saudi Arabia's coastal areas.

While it has diversified to include non-carbon projects in its portfolio, particularly hydrogen, oil and gas is still "the bedrock of the company", according to official statements. Saudi Aramco owns some of the world's most cost-efficient and least energy intensive oil reserves to develop; cheap, plentiful resources mean that the company could continue producing for as long as there is any demand.

Looking to the Future

Despite all these promising statements, however, if NOCs continue with the development and production plans they have announced, over the next decade they will produce more than 300 Bbo – close to the amount the oil industry as a whole should produce if the world is to keep emissions under the limits set in the Paris Accord.

So what will drive NOCs towards deeper involvement in the energy transition? Since many governments are heavily reliant on their state oil companies for revenue generation, they are unlikely to start imposing heavy restrictions or ambitious emissions reduction targets on them. Maximising income to fund important social and education programmes is often higher in a government's priorities than reducing carbon emissions. However, pressures to 'go green' from investors and from their own populations are expected to increase, particularly in countries where the physical effects of climate change are becoming evident. Importantly, to play an effective role in the energy transition, NOCs need to be financially robust and operationally sound and if possible to have transitioned out of the regulatory roles historically assigned to them.

Maybe NOCs need to be encouraged by their controlling states to imitate IOCs like BP and Shell, and start calling themselves energy rather than oil companies, concentrating on investment in alternative energy sources to help them and their countries move away from an unsustainable dependence on oil. It has to be said that it will be much easier for countries with large reserves to do this than for ones with smaller resources and less well developed energy industries, even if they have abundant alternative resources like wind and solar. If not properly planned, this transition could be very hard. Ultimately, the NOCs need to realise, as the IOCs have done, that this is a business opportunity that could help them look forward to an energy-rich future.

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Seabed Mineral Exploration

A role for oil field geoscience?

RICHARD COOPER, OFG Multiphysics

Seabed mining is very much in the news today, following initiatives from the Norwegian authorities who are encouraging companies and organisations to develop technical solutions to help kick-start and service what could be both a local and a global industry. Because of this, we have also seen several traditional oil and gas seismic players announce initiatives to support this market, and other markets such as wind farm developments and offshore groundwater.

The impetus for increased interest in this area is the accelerated demand for metals used for all things electric, in turn driven by the movement to reduce our dependence on hydrocarbons, particularly for transport. Demand is rising faster than onshore mining and recycling programmes can meet, pushing us to consider new sources of metals. Of course, there are also many environmental concerns raised by mining, both onshore and offshore, and the industry will have to balance the conflicting demands of the environmental impact of mining operations versus the need to decarbonise our transport infrastructure.

A casualty of the slowdown in demand for hydrocarbons has been the upstream geophysical industry. However, is it possible that exploration methods developed to meet the needs of the global hydrocarbon industry can be repurposed for application to seabed minerals?

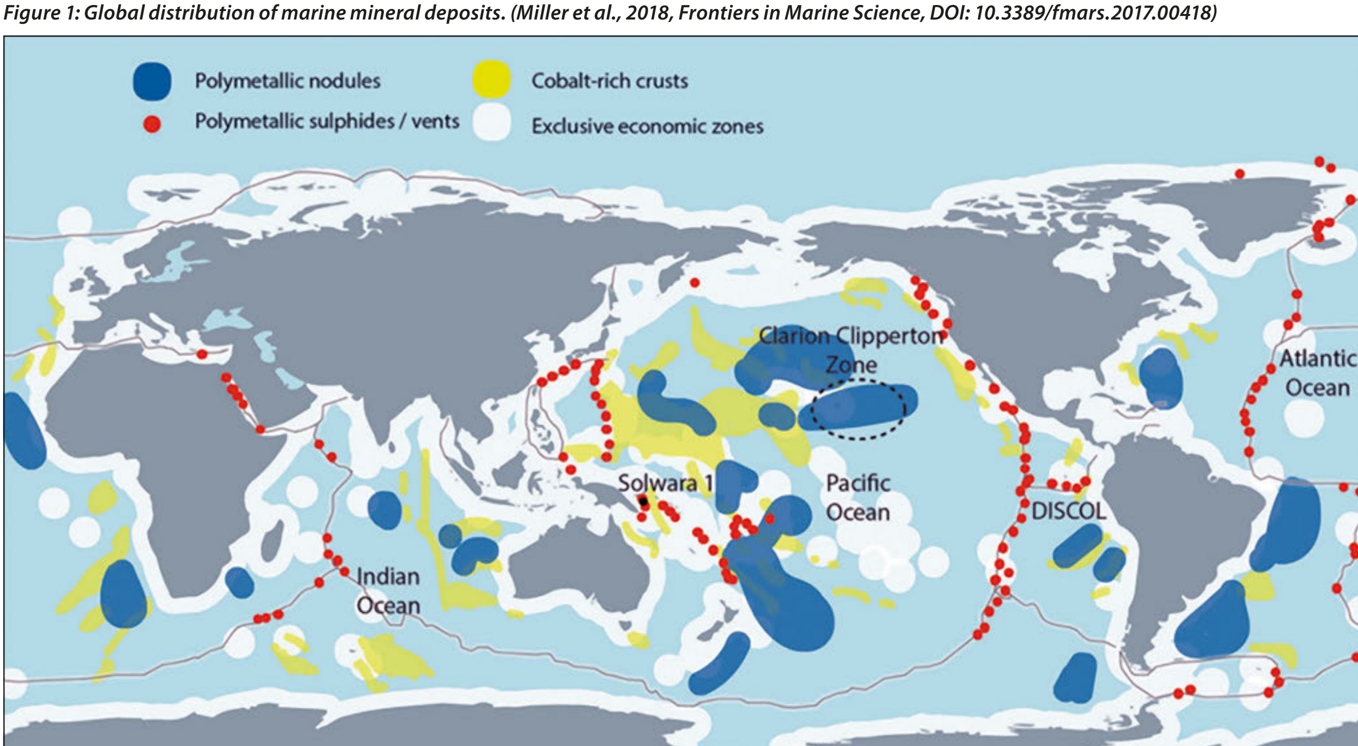
Seabed Mineral Deposits

Oceanic mineral deposits come in three basic flavours and are found throughout the world's ocean basins (Figure 1). Firstly, massive seabed sulphides (Figure 2a) which are associated with active and relict mid-oceanic ridge hydrothermal systems. These deposits are rich in copper, cobalt, zinc and other metals, and occur in water depths between 1 and 4 kms. Although other metallic deposits exist on the ocean floor, massive seabed sulphides receive the most press and in the public eye have become synonymous with seabed mining in general. This is firstly, because nearly all current exploration efforts have been focused on these deposits, and secondly, the protection of the unique biospheres which surround active ridge vents are of great concern to environmentalists. Two-thirds of the world's mid-ocean ridges are in international waters.

The second are seabed nodules (Figure 2b). Large areas of mainly tropical ocean seafloors are known to have accumulated these tennis-ball-sized polymetallic nodules which have a high concentration of key metallic elements. The accretion process is both extremely slow (millions of years) and poorly understood, with nodules confined to waters between 4 and 6 kms in depth in areas such as the eastern Pacific and the Indian Ocean.

Lastly, there are the metallic crusts (Figure 2c) which are found mainly on the flanks of seamounts, in depth ranges similar to those for seabed nodules and are of great interest, because of

Figure 1: Global distribution of marine mineral deposits. (Miller et al., 2018, Frontiers in Marine Science, DOI: 10.3389/fmars.2017.00418)



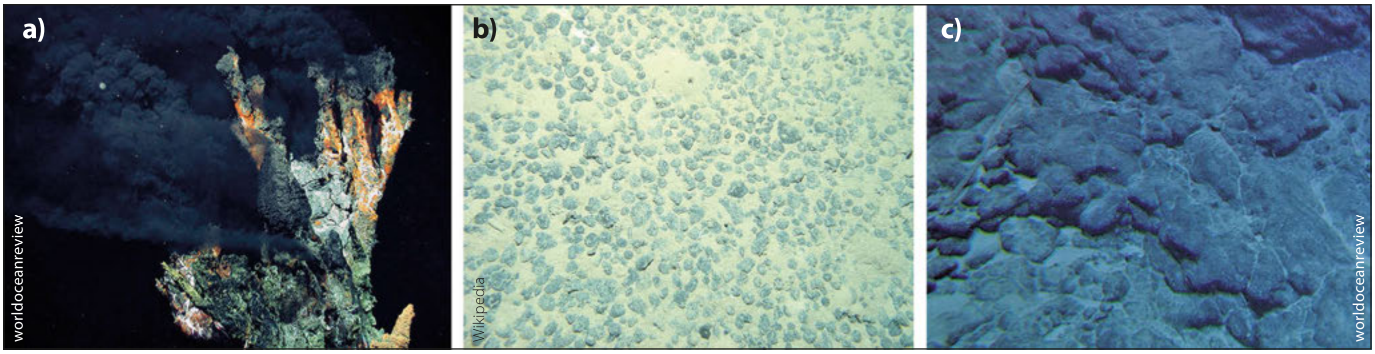


Figure 2: a) An active mid-ocean ridge vent site at which massive sulphides are deposited. b) Seafloor polymetallic nodules found in the deep ocean basins. c) Metallic crusts form primarily on the flanks of seamounts (image from https://worldoceanreview.com/en/wor-3/mineral-resources).

their high concentration of manganese and cobalt. These seamounts are mostly found within the Economic Exclusion Zone of smaller island nations.

Seabed Mineral Exploration

It would be reasonable to expect the seabed mining industry to follow commercial stages similar to the oil and gas industry, starting with reconnaissance exploration. Especially with many of the regions that could be explored extending over hundreds of thousands of square kilometres, it will be necessary to efficiently identify the sweet spots where mining activities could be focused. It will also be critical to identify the regions of specific environmental sensitivity where seabed mining activities might be limited or banned.

The next phase would include detailed mapping and monitoring. Mining engineers will need to know the grade of the ore deposits and their lateral and vertical distribution. Engineers will also need to understand the mechanical properties of the near surface, as well as other local parameters such as ocean currents, as these factors will impact the method(s) used for mining. Most of the small-scale commercial activities associated with seabed mining to date, have focused on this stage. Many have made use of Autonomous Underwater Vehicle (AUV) technology (Figure 3).

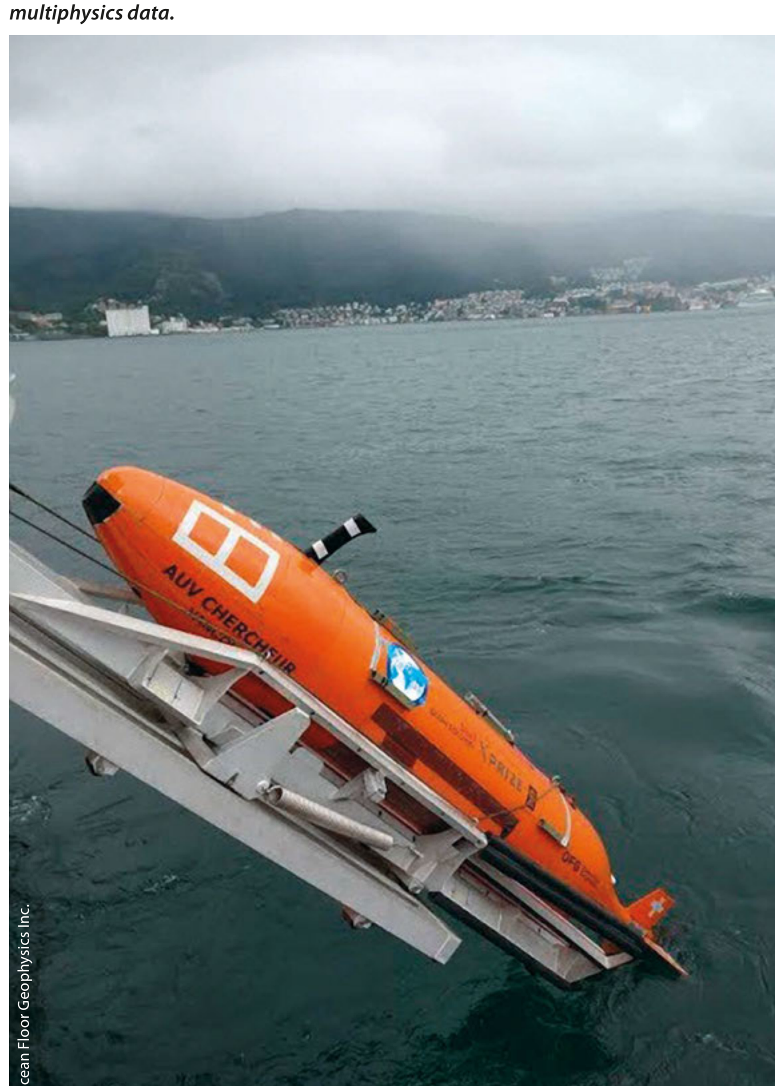
An AUV can be equipped with a range of sensors that can collect a rich multiphysics dataset in a single dive. The resulting interpretation (Figure 4) combines acoustic, electric, magnetic and geochemical information to characterise a sulphide deposit both in terms of its seafloor expression, and hidden subsurface structure.

Finally, as deposits are mined and depleted, mining sites will need to be decommissioned in an environmentally responsible fashion.

The Seismic Industry Seeks Green Pastures

As is obvious to all working in the oil and gas industry, a combination of depressed oil-price driven by oversupply and a reduction in demand exacerbated by the Covid-19 pandemic, has severely impacted the upstream business. The global seismic vessel fleet has reduced by approximately 80% over the past five years, with companies ceasing to trade, and others either exiting the marine seismic acquisition market and/or significantly reducing their vessel numbers. However, oil prices have risen recently and have stabilised around $60 bbl for Brent crude, and with travel restrictions expected to ease over the coming months as the pandemic is brought under control, we might expect a recovery in this sector as we enter a new cycle. However, the parallel rise in concern over climate change has forever changed the nature of the oil industry and we are now seeing an inexorable longer-term decline in oil consumption as the world transitions to greener energy alternatives.

Figure 3: AUVs equipped with a range of sensors can efficiently collect rich multiphysics data.



Given all of this, it comes as no surprise that upstream seismic industry players are keen to investigate new and greener markets. The model shown in Figure 4, was created from data acquired from a single seven-hour dive using a variety of AUV sensors. However, when considering reconnaissance-style surveying of large areas of the seafloor, AUV and/or nodal surveys may be too slow and too expensive. Surveys that deploy seafloor instrumentation may also be penalised on environmental grounds. This leads to towed-sensor methods as a viable method for surveying large areas efficiently and cost-effectively.

The seismic industry has developed sophisticated and scalable towed systems for the exploration and exploitation of oil field reservoirs. Can this technology be redeployed for seabed mining applications, with reference to the initial reconnaissance phase? To answer this question, we need to consider the needs of the seabed mining industry and to compare this to the world of oil and gas. Oil and gas reservoirs often lie several kilometres beneath the seabed and to exploit these reserves, petroleum geoscientists are interested in a range of earth properties such as structure and stratigraphy, lithology (mineralogy, porosity and permeability) and fluid type and saturation.

Compare this with seabed mining, where deposits will be located either at the seafloor, or only a few tens of metres below. Mining engineers will be interested in bathymetry, near-surface geology, presence, and concentration of metallic (conductive) ores, near-surface mechanical properties and related properties such as water chemistry and ocean floor currents. With this in mind, it is possible to sketch out in broad terms, the oil field data acquisition and processing technology that could be repurposed to meet the needs of a global seabed mining industry.

Data Acquisition

It will be necessary to image the seafloor geometry (bathymetry), and the geology a few hundred metres beneath the seafloor, in water depths between 1 and 6 kms. High resolution is key, with the ability to identify surface features with a resolution of 20m or better. Recent advances in towed-streamer acquisition geometries, such as the use of wide-towed sources and variable multisensor streamer geometries, can provide data suitable for high-resolution imaging of the shallow subsurface. (Figure 5).

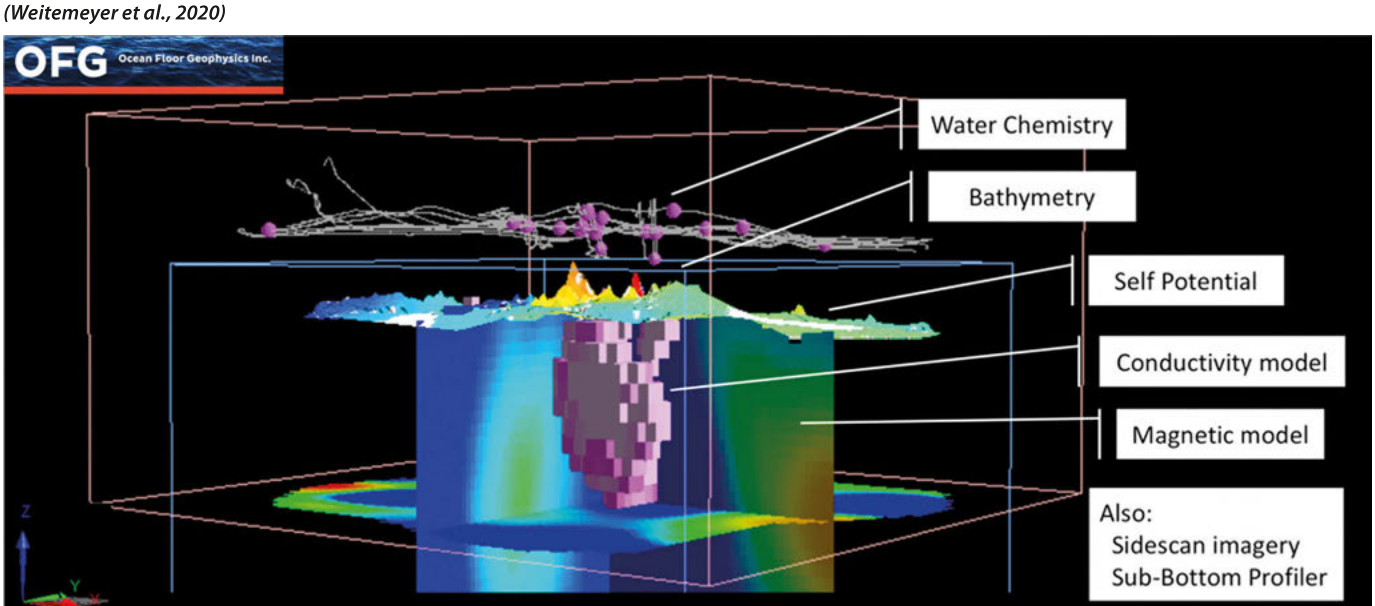
For onshore mining applications, electromagnetic (EM) and magnetic measurements are the geophysical tools of choice for identifying and quantifying ore bodies, and so it will be for offshore deposits. There are already existing methods available for acquiring shallow and deep-towed controlled source electromagnetics (CSEM) data which could be deployed to meet the needs of seabed mining. Ideally the seismic and CSEM data would be acquired simultaneously, using the same surface vessel or vessels.

The maritime industry is well on the way to developing a range of next generation vehicles offering unmanned, autonomous, and semi-autonomous operation, together with the application of novel propulsion systems based on hydrogen fuel cells and/or electric motive power. Such vessels will offer a much lower cost and environmental footprint than existing fleets, as well as being capable of operating continuously at sea for months at a time.

Data Processing and Interpretation

The oil and gas industry has developed sophisticated processing and interpretation algorithms and workflows which could be easily adapted and pivoted into the marine seabed mining market. These include wavefield imaging methods for generating high-resolution seafloor and near-surface images to yield bathymetry and shallow structure and stratigraphy. Multiphysics integration of seismic and CSEM data can quantify the distribution of metallic elements

Figure 4: Detailed mapping of a massive seabed sulphide system using a multiphysics AUV platform. All the data was collected in a single AUV dive, and combined to characterise both the seafloor expression and subsurface structure of the sulphide bodyImage courtesy of Ocean Floor Geophysics Inc. (Weitemeyer et al., 2020)



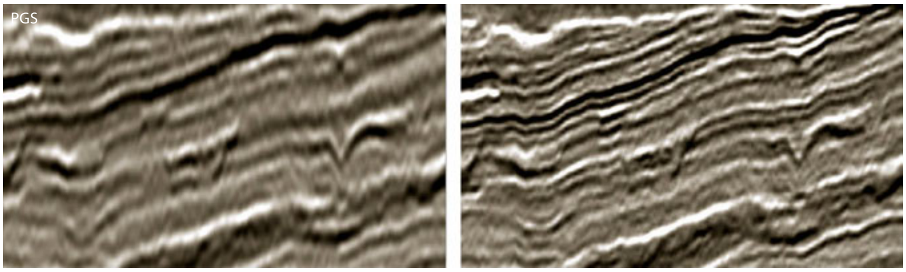


Figure 5: Resolution uplift achievable when higher frequency data are recorded and preserved in the processing and imaging of multisensory seismic data. Conventional (left) versus full frequency bandwidth processing (right). Seismic data courtesy of PGS.

in the near surface. Rock-physics advances, driven by interest in shale plays and unconsolidated sediments, can be used to convert geophysical attributes to mechanical properties of specific interest to mining engineers. Machine learning (ML) and artificial intelligence techniques (AI), applied to 'big data' can also be utilised for seabed mineral exploration. As we accumulate larger and richer datasets, it should be possible to use AI/ML approaches to mine both structured and unstructured data to help identify areas of economic and environmental interest. The real promise of these approaches is that the more data acquired, the more robust such predictions become.

Fit for Purpose

It is important that geophysicists demonstrate to engineers as early as possible the value of the information and knowledge we can acquire. Within the oil field sector, drilling and reservoir engineers use geophysical data sparingly, and it has been seen already in more mature markets for industries such as wind farm development, that geophysical methods play only a limited role as a complement to geotechnical measurements. In the oil industry, the challenge for geophysicists to meet the need of engineers can be summed up in three statements: too expensive, too slow, and engineers need properties with uncertainties defined in depth, not geophysical attributes in time. So, for geophysics to be relevant in new markets, they need to focus not just on the acquisition technology but understand the need to complement more traditional and well-established geotechnical measurements by being competitive in terms of cost, time, robustness and relevance of information.

The most profitable components, indeed perhaps the only truly profitable components, of the upstream oil and gas seismic industry have been associated with multi-client business models where data is acquired once and re-sold to multiple parties over multiple years. Often these datasets are supplemented with new data and/or new processing and interpretation methods, further extending the return on the initial investment in data acquisition. A question to be answered is whether similar business models will become available to geophysical providers to the seabed mining industry.

Seabed mining is not yet an industry; it might be better described as a nascent industry, with a variety of government and commercial organisations around the world working to understand and develop the technical and commercial environment to support the possible development of seabed mining. Development of deep-sea mineral mining technology is underway, though the water depths involved present significant challenges. Environmental concerns are significant and must also be addressed before seabed mineral resources can be responsibly utilised. Geophysical technology, modified for studying the shallow subsurface and deployed from efficient autonomous platforms has the potential to provide information to make robust environmental decisions and to guide responsible exploitation of seafloor mineral resources.

References provided online. ■

Australia's Beetaloo Shale Play

JONATHAN CRAIG,
NVentures Ltd

A rival to the North American Marcellus Play?

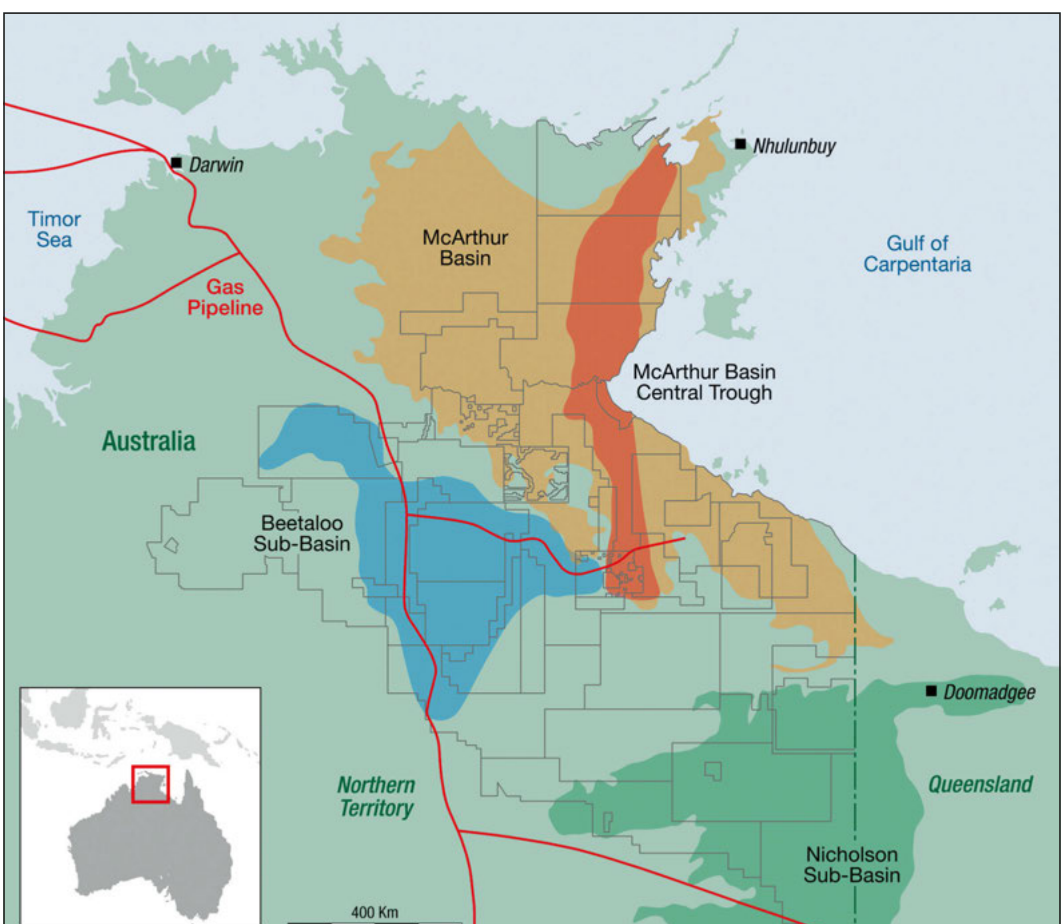
The Beetaloo Basin has, until recent years, been underexplored, with explorers believing the Palaeoproterozoic to Mesoproterozoic (1.0–1.7 billion years ago) sequences too old to support hydrocarbons. However, following successful drilling campaigns in recent years, spurred on by advances in unconventional drilling technology, this perception has altered dramatically. Added to this, with the lifting of a fracking ban in 2018 and new incentives, oil companies are now positioning themselves for an exploration and development drive over the next few years, which could see Beetaloo rival the great shale plays of North America.

Beetaloo Geology – Sometimes Age Doesn't Matter

The Beetaloo is a sub-basin within the greater McArthur Basin, in the Northern Territory (NT) of Australia, some 600 km south of Darwin, covering an area of approximately 28,000 sq km. In its 2018 petroleum assessment, the USGS estimated undiscovered, technically recoverable mean resources of 429 MMbbl of continuous oil and 8 Tcf of continuous gas in the Beetaloo Basin. However, this may be a conservative estimate with Origin Energy estimating resources of 6.6 Tcf (2C) and Empire Energy 3.5 Tcf for its EP187 permit alone. The two main intervals with the greatest hydrocarbon potential are the Kyalla and middle Velkerri Formations of the Roper Group, which are some of the oldest proven hydrocarbon source rocks in Australia. The reason for this is that the rocks have not undergone excessive deformation or been thermally stressed. Both contain favourable properties for the generation of shale gas, including mineralogy, organic geochemistry and maturity. The formations are also significantly thicker than North American shale plays where average thicknesses are between 20m (Barnett Shale) and 100m (Eagle Ford). In the Beetaloo, Empire recorded net thickness of 270m in the Velkerri interval and Origin, almost 900m thickness over the entire Kyalla section, with gross thicknesses of each interval at 75–125m.

World Class Flow Rates and Resources

A relatively small number of exploration wells have been drilled to date, with initial gas discoveries made in 2014–2015 by Origin Energy and Santos. Tanumbirini-1 (Santos), was successfully re-entered and tested in 2020, significantly



exceeding expectations, with an initial peak gas rate of ~10 MMscfd, and an average rate of 2.3 MMscfd over the first 90 hours of testing. Fracking at Tanumbirini-1 indicates that horizontal wells in the Beetaloo's middle Velkerri Shale Formation have the potential to be similar or better than wells in the Marcellus Shale Play, the most prolific in North America.

To date, Origin has identified four stacked, unconventional plays in its acreage, namely, the Velkerri liquids rich and dry plays, Kyalla liquids rich play and Hayfield Sandstone oil/condensate play. The company recently booked 6.6 Tcf contingent resource relating to the Velkerri B shale dry gas play. Origin confirmed the Kyalla 117 N2-1H ST2 well as a gas discovery with early-stage flow rates of 0.4–0.6 MMscfd recorded over 17 hours, with detailed evaluation expected in the second quarter of 2021 once extended testing is completed.

The October 2020 discovery, Carpentaria-1 (Empire Energy) also found liquid-rich gas in the Velkerri Shale, but at a shallower depth and over a greater proportion of the formation compared to analogue wells in the Beetaloo Basin. Empire booked best estimate contingent gas resource of 41 Bscfg in the immediate vicinity of the Carpentaria-1 well location, with resources for its EP187 permit increased by 47% to 3.5 Tcf. Empire is now preparing a fracking campaign for the second quarter of 2021.

Government Backs Development

Just as the Victoria Government announced a lifetime ban on fracking in the state, the NT Government has gone all-in, with a strategic plan to accelerate gas exploration and development in the Beetaloo Sub-basin and to create thousands of jobs. It has also set aside A$50 million incentives for exploration that starts before 30 December 2022, with hopes of commercial production beginning at the latest by 2025. Further to this announcement, the government outlined more investment in January 2021, which includes financing of more than A$220 million to improve infrastructure, an efficient but rigorous regulatory environment and working with local communities.

In April 2021, Empire Energy signed a sale and purchase agreement with Pangaea and Energy & Minerals Group, becoming sole operator for five permits across the basin, enhancing its early commercialisation plans, with multiple drill-ready targets and excellent access to the gas pipeline infrastructure. Further east, in the greater McArthur Basin, Armour Energy has lodged the first applications for retention licences in the area over portions of EP 171 and 190, aiming to sell gas from late 2022 onwards. The company also announced that it is to demerge the ASX-listed Northern Basin Oil & Gas Business into a newly formed company named McArthur Oil & Gas, which will be separately listed on the ASX. Meanwhile, Santos's partner Tamboran Resources added Dick Stoneburner as Chairman, who as founder and president of Petrohawk Energy was a key figure in the $US12.1 billion sale of the US shale firm to BHP in 2011. Stoneburner describes the play "as good as any shale play I've seen": further testament to this emerging basin. ■

Robots on the Seabed

Will automation in ocean bottom seismic revolutionise operations?

IAIN BROWN

It is generally accepted within the seismic acquisition industry that seabed seismic receivers deliver superior seismic data and consequently better seismically derived subsurface images. However, seabed receiver or ocean bottom node surveys (OBN) are currently not as widely used as towed streamer seismic, primarily because of the higher acquisition costs.

In general, seabed surveys are only considered for the most challenging geophysical objectives such as reservoir management projects and the imaging of complex geological objectives where high repeatability and full azimuth measurements are required.

A modern quality OBN design can deliver many times the data of a streamer survey. It may also offer superior azimuthal distribution, and in some cases can even be more cost effective through higher productivity enabled by simultaneous source acquisition and refinements in node handling systems.

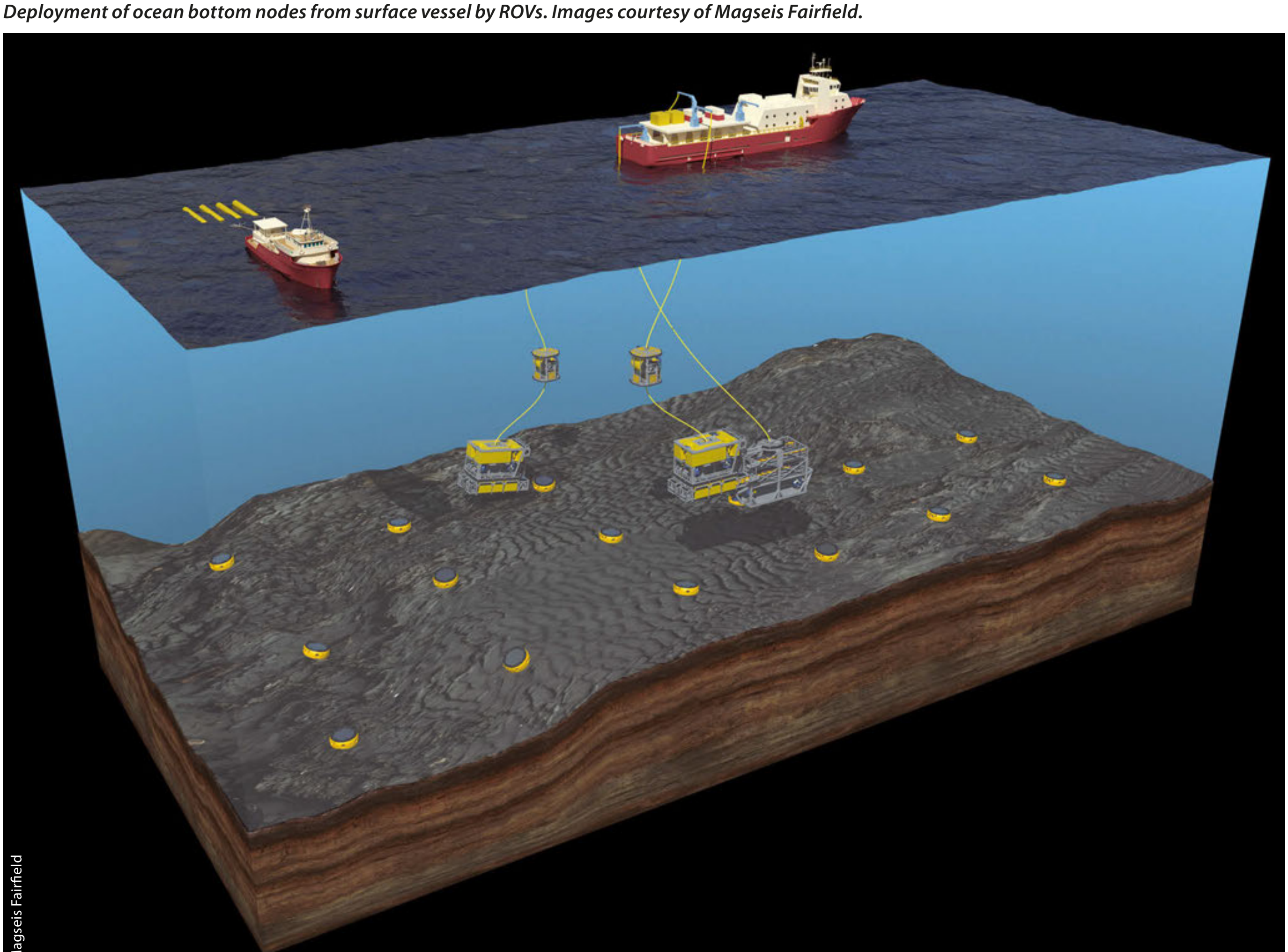
Automation, Step by Step

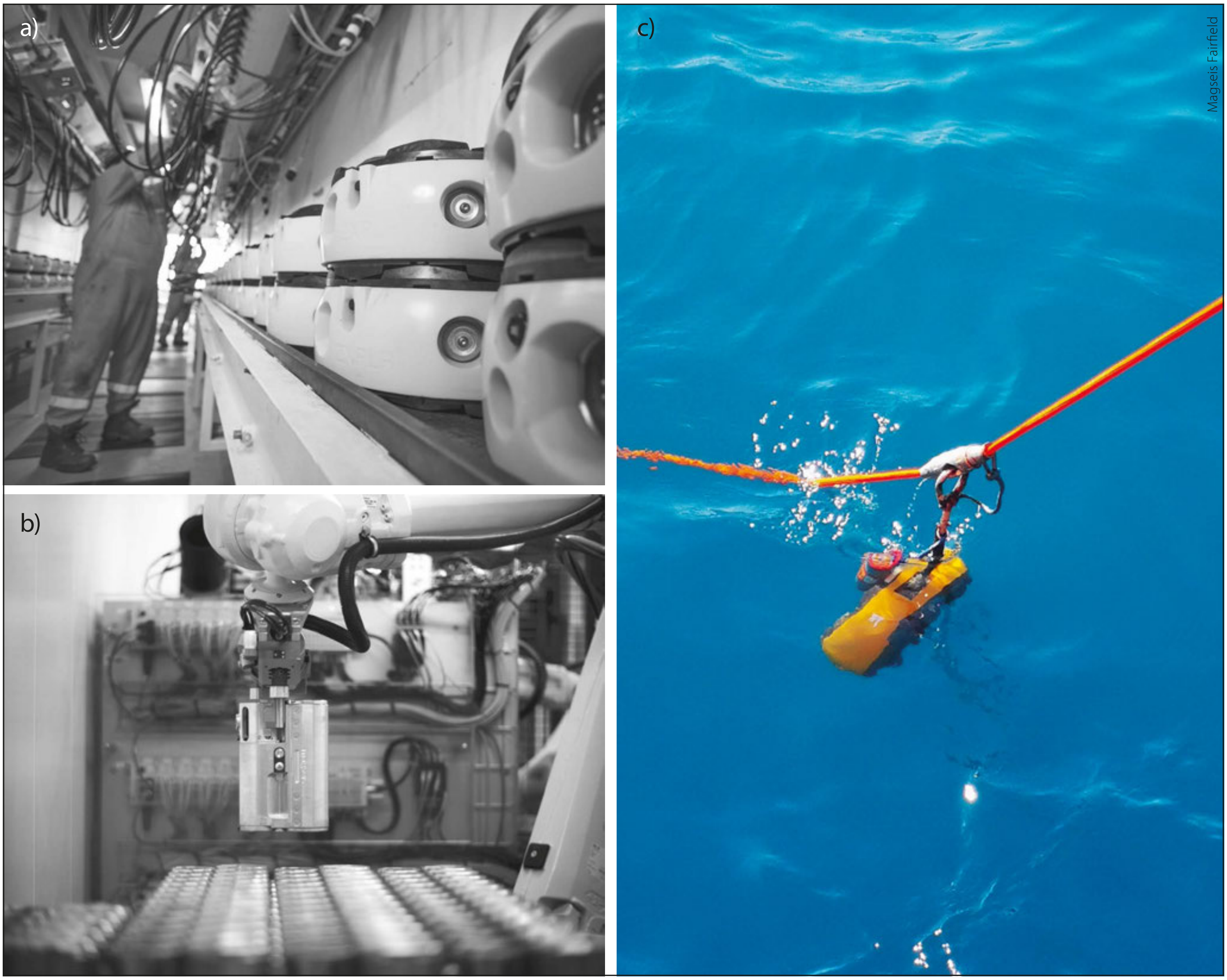
In recent years, there has been significant engineering effort around more efficient seismic node deployment and retrieval to address this cost differential, and thus open seabed node acquisition techniques to a wider range of exploration and development challenges.

Initially OBNs were exclusively deployed by remote operated vehicles (ROVs). These submersible machines have robotic arms, known as manipulators, a camera for subsea visual analysis, electrical drivers for motion control and onboard batteries or external umbilical cables for communication and power delivery. ROVs for exploration were introduced during the 1970s and represented a significant technology upgrade as they were designed to operate at extreme pressures and low temperature conditions. These systems remain in use in marine environments but can be costly for node deployment.

One of the most developed systems currently in use for cost-effective OBN deployment and retrieval is the nodes-on-a-rope (NOAR) deployment

Deployment of ocean bottom nodes from surface vessel by ROVs. Images courtesy of Magseis Fairfield.





a) Node being deployed on cable (rope); b) nodes on a conveyer pre-deployment; c) robotic node handling system. Images courtesy of Magseis Fairfield.

system. This method is becoming widely accepted and can allow placement down to 1,500m and theoretical deployment and recovery speeds of up to 5 knots with nodes at 25m spacing, which is significantly faster than conventional ROV deployment, where the nodes are placed individually on the seabed. However, in real-world situations, NOAR deployment efficiencies are often reduced by seabed infrastructure such as pipelines, cables, and other systems. In these instances, the rope must be terminated and restarted rather than crossing the obstructions which can slow the operation. Node positioning requirements can also have a major impact on deployment efficiency, with many oil companies imposing tight positioning specifications for the nodes that require precision placement that can only be achieved at slower speeds. In NOAR operations, up to 10,000 nodes can be carried on a single vessel, and automated robotic node handling, battery-change and data-docking and downloading systems are now highly developed.

A Swarm of Seismic Drones

If it becomes possible to drive OBN acquisition costs down even further, it could open higher quality subsurface imaging to exploration activities and not just for particularly challenging imaging objectives or 4D monitoring of producing assets.

These efforts include evaluation and development of autonomous underwater vehicles (AUVs) with fully integrated seismic nodes, which can navigate independently to and from the deployment location. These new systems would use a modified surface vessel or 'vessel of convenience' as the 'mother ship' that would both deploy and retrieve the AUVs as well as monitor operations.

There are several companies currently engaged in this endeavour. Most of them envisage a system which is very highly automated with the seabed nodes having the capability of navigating to a predetermined location on the seabed, coupling to the seafloor and then moving on to a second (or several) locations thereafter, whilst the source vessel shoots overhead. Envisage a 'swarm' of these robotic nodes operating independently, but in concert with one another. It is envisioned that the introduction of robotics in seismic acquisition activities will significantly reduce costs and importantly, minimise human intervention and consequently, HSE risk.

The ultimate ambition of these systems is to automate nodal seafloor acquisition operations so that they will eventually match wide-azimuth towed streamer costs and turnaround times, while at the same time retaining the technical advantages of the OBN systems. An ambitious goal perhaps, but maybe not an impossible one.

The Pioneers

In this brave new world of autonomous nodes, there are currently few players. An early entrant was UK-based Autonomous Robotics (ARL). They are developing technology that they hope will allow the safe deployment and recovery of over 1,200 underwater 'Flying Nodes' in 24 hours and be operable up to sea state 5. Their nodes will have a depth rating of up to 3,000m and are being designed to allow a seabed 'loiter' period of up to 12 months with a maximum seabed seismic recording time of 60 days. ARL was awarded a grant in April from the Oil and Gas Technology Centre (OGTC) and two European energy companies to develop a bespoke seismic sensor to fit in the company's 'flying' nodes and limited sea trials have been conducted off the UK's south coast. In 2022 they are expecting to deploy 5–10 pre-production nodes in further sea trials.

Another project is a joint venture between Saudi Aramco and Fugro's subsidiary Seabed Geosolutions which has been developing an autonomous OBN system called 'SpiceRack'. Saudi Aramco won the Best Exploration Technology Award at the 2018 World Oil Awards for this system and the technology appears to have successfully conducted limited prototype AUV sea trials in the Arabian Gulf in 2017. PXGEO Seismic Services Limited recently announced a binding agreement with Fugro to acquire certain assets of their OBN business, with the transaction expected to complete mid-2021. What this means for the SpiceRack project though, is currently unclear.

Another of the more recent entrants is Blue Ocean Seismic Services (BOSS), which was formed with Australia-based companies, Blue Ocean Monitoring and Woodside Petroleum, and joined in 2020 by BP Ventures as a key investor and co-venturer. BOSS has considerable experience of AUV operations and announced that it had successfully completed sea trials of it's testbed ocean bottom seismic robotic vehicle (tOBSrV) in Australian waters in May this year. The next phase will be to construct and test 10+ 'alpha' prototypes,

ARL 'Flying' Node.

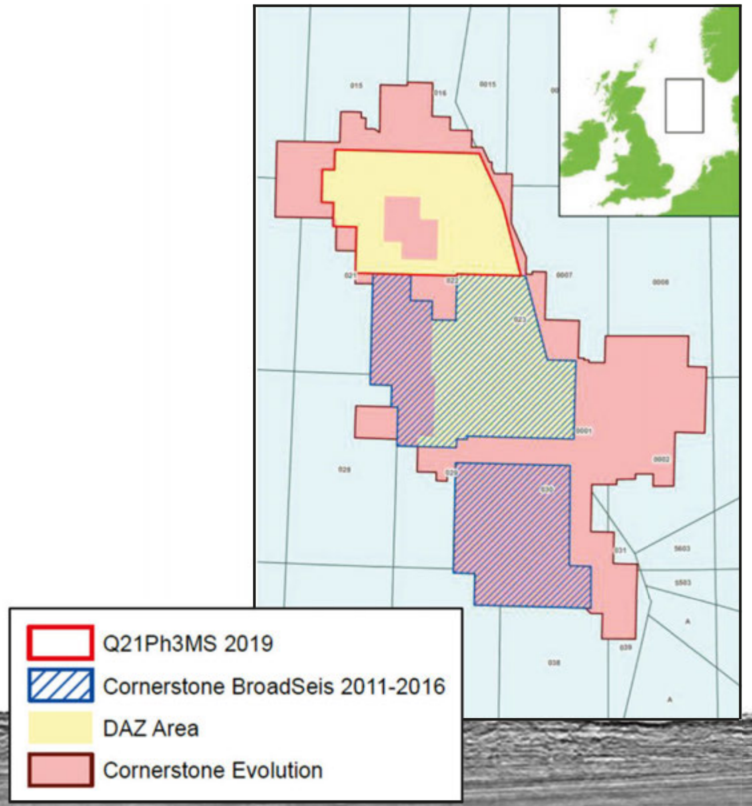
Proposed BOSS Autonomous OBN.

iDROP Oceanid Node.

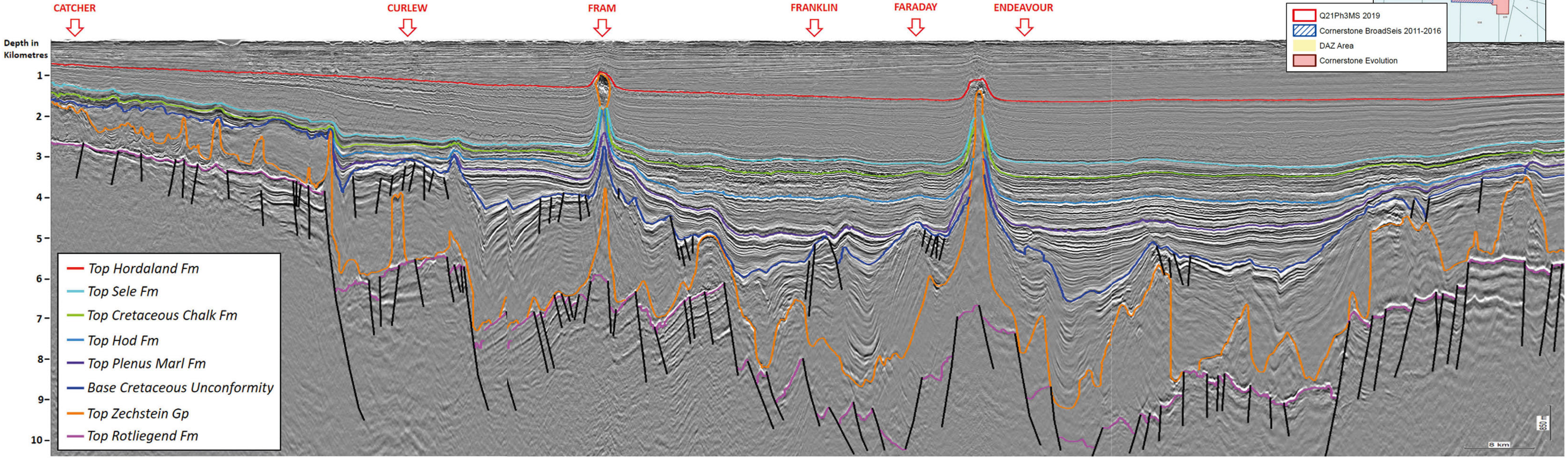
UK Continental Shelf:

An Evolution in 3D Seismic Imaging of the Central North Sea

The Central North Sea is a mature petroleum exploration province, with over 50 years of exploration to date. With increased maturity, recent exploration efforts have focused on the deeper targets below the Base Cretaceous Unconformity (BCU), where there is increased risk and often high-pressure, high-temperature (HP-HT) conditions. The key to de-risking these plays is high quality seismic data with good frequency content and high signal-to-noise ratio at depth. With Cornerstone Evolution, CGG has utilised the latest seismic processing technologies to achieve these goals, producing the best-quality regional imaging in the area to date.



Interpreted arbitrary line oriented north-west to south-east across the Cornerstone Evolution data. The line spans the entire Central Graben and intersects several fields and discoveries.



Exploring the Deeper Potential of the Central North Sea

With recent successes, such as the Glengorm and Isabella discoveries, the Central North Sea is proving that the deeper potential may hold the key to future exploration.

MATTHEW DACK, formerly CGG, and GREGOR DUVAL, CGG

The complex geology of the Central North Sea (CNS) has historically proven to be a challenge for the seismic imaging of deeper targets in the basin. These challenges include the relatively shallow water (<100m), complex Tertiary and Quaternary deposits with shallow channels, contourites and shallow gas anomalies, a thick and hard layer of Cretaceous chalk and complex deep tectono-stratigraphic evolution related to Mesozoic rifting and halokinesis of the Permian Zechstein salt. These, combined with a thick overburden within the basin axis that leads to high-pressure, high-temperature (HP/HT) reservoir conditions, have meant that the targeting of deeper plays in the area has historically been high-risk. Fortunately, recent advances in seismic imaging technologies, including improvements in depth imaging and migration techniques, are providing new insights to reduce the risks associated with these plays.

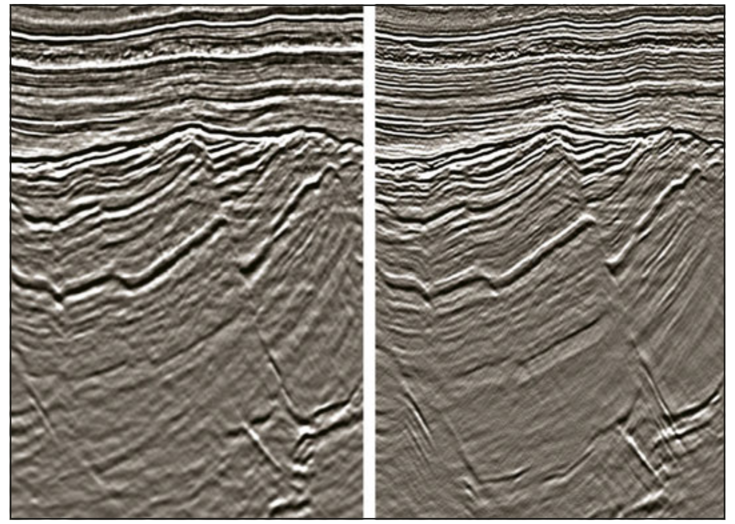
An 'Evolution' in Seismic Imaging

CGG recently undertook a two-year, ground-up, reprocessing project of its entire Cornerstone data set in the CNS. The new Cornerstone Evolution data consists of over 50,000 km² of 3D long-offset seismic data acquired over the past three decades, across 10 quadrants of the UK and Norwegian Central North Sea, from UKCS Quadrant 38 in the south to UKCS Quadrant 15 in the north (see foldout map). The final Evolution data comprises a series of surveys acquired with conventional flat-tow acquisition in a north–south orientation. It also includes the data from CGG's first multi-sensor streamer survey in the region, using Sercel's Sentinel® MS technology, and its BroadSeis™, variable-depth steamer broadband data, acquired in a west–east azimuth to provide over 18,000 km² of dual-azimuth (DAZ) data coverage in the region.

The main objective of the Evolution reprocessing project was to improve the illumination and depth positioning of deeper targets (Figure 1), increasing the signal-to-noise ratio, whilst ensuring the amplitude-versus-offset (AVO) fidelity of the data. To achieve this, the data was reprocessed from its original raw state (i.e., field tapes) and the latest imaging technologies were applied, including enhanced joint source and receiver deghosting and fully data-driven model-based shallow water demultiple and short-period multiple suppression algorithms. To achieve the most reliable velocity model to date for accurate depth imaging, it was calibrated to 10 regional structural horizons and more than 200 wells. The key horizons incorporated into the depth model building included: Top Sele Formation, Top Cretaceous Chalk, Top Cromer Knoll Group, Base Cretaceous Unconformity, Top Salt and Base Zechstein; some of which are indicated on the foldout image.

Furthermore, with advances in computation power and algorithm efficiency, Q-FWI (Full Waveform Inversion) was run across all input data, inverting for both absorption (Q) and velocity for high-resolution modelling of the overburden. In addition, CGG's proprietary Time-Lag FWI which incorporates reflections and refractions was also run for deeper velocity updates within the complex Cretaceous chalk layer. The velocity modelling sequence incorporated salt scenario testing with targeted Reverse-Time Migrations (RTM) for 24 piercing salt diapirs within the region. This, combined with a velocity model constructed in both the north–south and east–west azimuths, resulted in the most advanced regional velocity model constructed in the area to date, to achieve reliable depth imaging of the deeper structural targets (Figure 1).

Figure 1: Comparison made in the Two-Way Time domain between the legacy TomoML PSDM and the new Evolution PSDM data. The example shows improved frequency content, signal-to-noise ratio and illumination at depth below the Base Cretaceous Unconformity (BCU).



Exploring Deeper

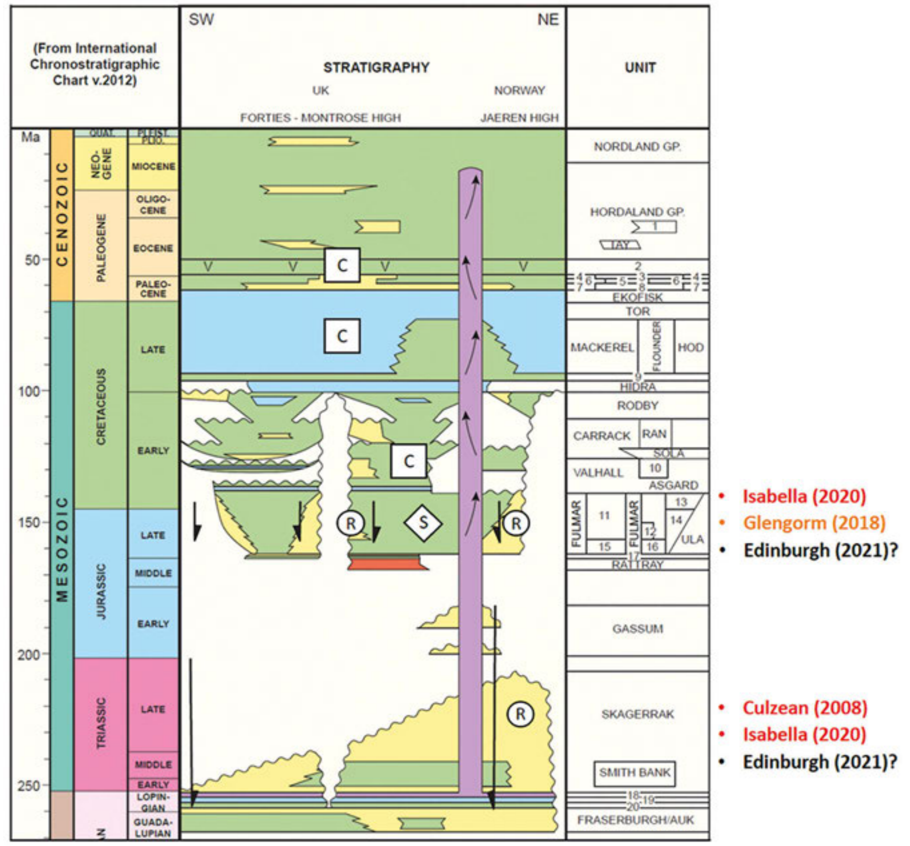
In the last 10 years of exploration in the CNS, 124 exploration wells have been drilled in UK and Norwegian waters. Of these, over 50% have targeted the deep Jurassic and Triassic plays with varying success. Yet, recent successes targeting these plays have increased focus on the deeper potential of the basin (Figure 2). The first of these successes was the Culzean discovery in 2008 by Maersk, when well 22/25a-9 encountered hydrocarbons within Middle Jurassic Pentland Formation and Triassic Skagerrak Formation sandstones. This was followed by several smaller discoveries prior to the discovery of Glengorm in 2018 in Quadrant 22. Drilled by well 22/21c-13, it encountered hydrocarbons in high quality Upper Jurassic reservoirs. More recently, however, the Isabella discovery has further increased focus on the deeper potential. Drilled by Neptune with the 30/12d-11 well in early 2020, the well encountered 64m of net pay, again within Upper Jurassic and Triassic sandstone reservoirs. This exploration trend looks set to continue with the planned drilling of the high-impact 'Edinburgh' well, by Shell and its partners in 2021. The reservoir target, similar to Isabella, is within a tilted-fault block adjacent to a Permian salt diapir and likely contains Jurassic and Triassic reservoir intervals.

A Clearer View

Reservoir presence and effectiveness are critical risk components when targeting the deeper HP/HT plays of the Central Graben. High quality seismic data is therefore essential to de-risk these plays. With Cornerstone Evolution, particular attention has been paid to the deeper imaging. Historically, the presence of peg-leg, inter-bed and water-bottom multiples has adversely affected the imaging below the Base Cretaceous Unconformity (BCU), where structural targets are comprised of highly faulted and rotated fault blocks. The use of advanced multiple-suppression algorithms, such as 3D SRME, MWD and Wave-Equation deconvolution, has dramatically improved the signal at depth. This, combined with Least-Squares Kirchhoff migration, which has further enhanced the deeper image by reducing the high-frequency random noise, is helping to identify new deep potential with the identification of a number of undrilled structural targets based on the new data (Figure 3).

All images courtesy of CGG Multi Client. ■

Figure 2: Chronostratigraphic chart from CGG's Basins & Plays database highlighting the main play elements and recent discoveries for the Jurassic and Triassic plays in the Central North Sea.



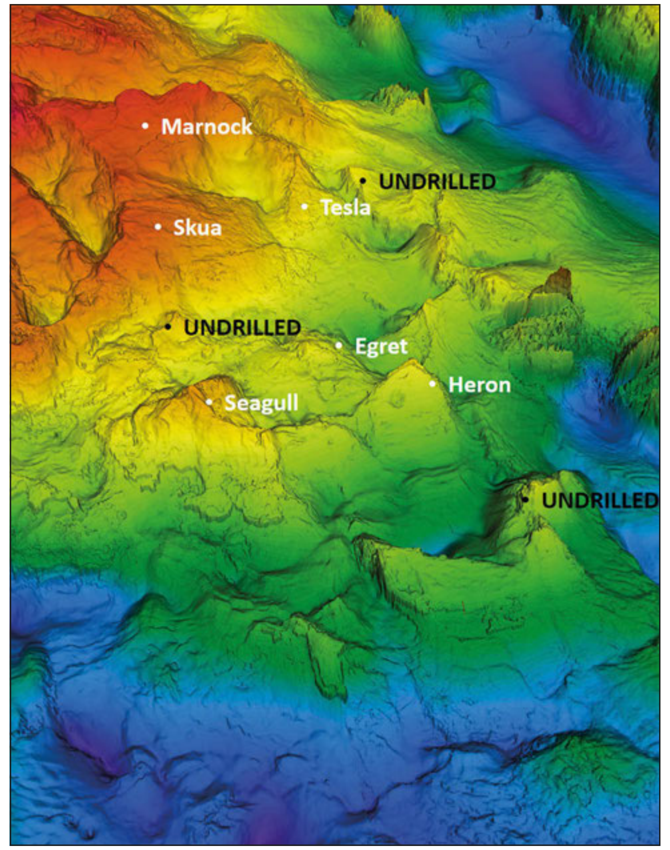


Figure 3: BCU depth structure map highlighting some of the key producing fields and undrilled structural potential at Jurassic–Triassic level.

culminating in a seismic sea trial late in Q3, 2020 in the North Sea.

A Norwegian technology firm, iDROP, has a taken a different approach with its autonomous Oceanid nodes. This system is based on individual cylindrical sensor nodes that are free-fall deployed, using gravity and ballast shift for propulsion and position control. These land at specific pre-planned positions on the seabed and then release the ballast to return to the surface for data retrieval. In March 2021, the system was mobilised for a fjord test and the company plans two further industry-funded offshore pilot-demos later this summer. These will be to verify the data quality uplift using low frequency geophones and to test the operational efficiency.

All these companies envisage fully containerised, scalable, and modular solutions, deployable from vessels of opportunity, enabling efficient and cost-effective mobilisation to survey locations. They are also developing similar solutions, often adopting and modifying technologies from other industries as well as developing new ones. With the creation of new intellectual property (IP) comes the defence of competitive advantage. There has been regular patent litigation in the seismic equipment world and this will be another area of intense activity and scrutiny, with developers keen to stay one step ahead of the competition by protecting IP advantages.

Disruptive Engineering

The technical challenges for these pioneers remain substantial and are predominantly engineering related. Battery size and endurance, command-and-control and the launch and recovery systems are all significant hurdles to overcome, but all of these should ultimately be addressable within moderate timeframes.

Another significant challenge in the implementation of autonomous operations is the currently limited communication capabilities between robotic units. For fully autonomous, robotic OBN systems to work, it is imperative that these systems communicate seamlessly to unlock their true value. The implementation of such communication systems is both complex and costly and will involve collaboration across several different industries. Lastly, and perhaps most importantly, for these systems to be used for larger scale exploration seismic programmes, the key is reducing the unit cost of the autonomous nodes, so that eventually 100,000+ units are deployed in a single survey.

When the Covid-19 pandemic and economic downturn is finally past us, oil and gas operators and service companies will have to continue exploring new avenues for cost reductions to be better equipped to withstand future market declines. Rystad Energy, in a report that investigated the adoption of robotics across the petroleum industry, found that existing robotics solutions could replace hundreds of thousands of oil and gas jobs globally and reduce labour costs by several billion dollars by 2030, but only if the industry aggressively adopts robotics. If these robotic systems develop quickly enough, they could be highly disruptive in the seismic space and as we have seen in the airborne drone world, the technology can move at a frightening pace. ■

Dalmatia: Where Karst Meets Coast

LON ABBOTT and TERRI COOK

This famously beautiful Mediterranean coastline stretching between Montenegro's Bay of Kotor north-west to Croatia's Rab Island, features craggy mountains, rugged islands in an azure sea, and waterfalls tumbling over travertine into emerald pools.

Dalmatia is the name given since Roman times to the Balkan Peninsula's mountainous west coast. Those mountains, the Dinarides (also called the Dinaric Alps), are a series of roughly parallel south-east trending ranges that stretch from Slovenia's Julian Alps in the north, through Croatia and Montenegro, to Albania in the south. They constitute a fold and thrust belt produced by continental collision between Eurasia and Adria, a microcontinent that separated from Africa during the closure of the Tethys Ocean. That collision produced the Alps and Apennine ranges in addition to the Dinarides. Italy's east coast and Croatia's Istrian peninsula, along with the floor of the intervening Adriatic Sea, constitute the microcontinent, which is being thrust beneath Eurasia to form today's Dinaride fold and thrust belt.

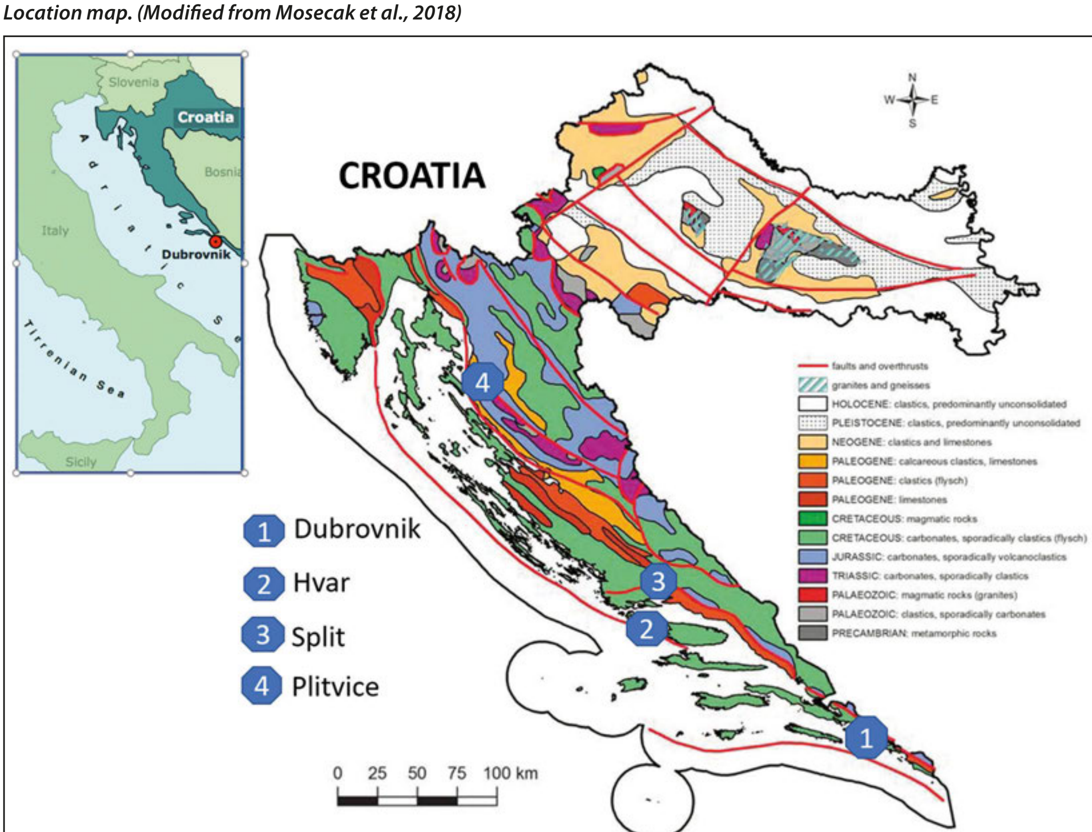
The Dalmatian coast features dozens of significant islands and more than 500 islets. Croatia, where most of Dalmatia is situated, is not a large country; the straight-line distance between its coastal extremities is a mere 526 km, but thanks to the region's many islands, it boasts a coastline stretching more than 5,800 km. Dalmatia's islands are a product of its collisional setting; the sea has inundated the fold and thrust belt, drowning the synclines, whereas the anticlines stand as echelons of long, narrow islands. Collision began in the Eocene and continues today. Convergence is proceeding at a rate of 4.5 mm/yr.

During the Mesozoic, both the Eurasian and Adrian margins of the Tethys were blanketed by thick sequences of shallow marine carbonates, which were folded and thrust up to form the Dinaride mountains. Because the range consists almost exclusively of those carbonates, karst features abound; in fact, the term *karst* is derived from Slovenia's Kras plateau, which rises a short distance north-west of Dalmatia. Dalmatia's karst topography combines with its dry Mediterranean climate to make flowing rivers rare commodities. But the springs where water exits the limestone form scenic wonders that leave an indelible impression on travellers to this idyllic land.

'Fjords' and Fortified Cities: Southern Dalmatia

Dubrovnik, nicknamed the 'Pearl of the Adriatic', is an excellent place to begin your tour of Dalmatia. Dubrovnik rose in 1358 to become a powerful independent city-state known as the Republic of Ragusa. Its wealth stemmed from its prominence in maritime trade, which reached a zenith in the 14th and 15th centuries. Thanks to skilful diplomacy, Ragusa maintained its independence until 1808, when it fell to the armies of Napoleon. In 1991, near the beginning of the

Location map. (Modified from Mosecak et al., 2018)



protracted wars that sundered Yugoslavia, the Yugoslav National Army laid siege to Dubrovnik for eight months.

The Stradun, Dubrovnik's main promenade, hosts colourful market stalls by day and, on warm summer nights, tables for candle-lit dinners amidst the city's medieval ambiance. The Old Pharmacy, which has been in business since 1317 and hosts an interesting museum, stands in the courtyard of a Franciscan monastery just off the Stradun. Keen walkers will delight in circumambulating the old city atop its thick limestone walls, peering down on the town's beautiful churches, palaces, and homes, all bedecked with orange tile roofs. The city was almost completely destroyed by a magnitude M=7 earthquake in 1667, so most of the public buildings you see were rebuilt after that date, accounting for the city's primarily Baroque architecture. For an even loftier perch, with expansive views of the city below and the Dalmatian islands to the north-west, hike or take the cable car up Srd, the almost 400m-high hill that rises behind Dubrovnik.


Lon Abbott/Terri Cook

Dubrovnik from the start of the Srd hill climb.

Montenegro's Bay of Kotor, often mistakenly called Europe's southernmost fjord, is southern Dalmatia's other scenic highlight. You'll see why so many people call it a fjord when you drink in the views of its steep, imposing limestone mountains that plummet to a narrow inlet of the sparkling Adriatic Sea on the 92 km drive there from Dubrovnik. Although the Bay of Kotor strongly resembles a fjord, it was not carved by a glacier, so it is technically a ria. Like all rias, this impressive bay was instead created when rising sea levels drowned an ancient river valley. Like the drowned synclines that separate Dalmatia's anticlinal islands from the coast, the bay is a product of downward lithospheric flexure in the active collision zone.

Thanks to the protection from storms the ria affords to ships, Kotor was an important harbour and trading hub throughout the Middle Ages. The town was variously controlled through the centuries by the Serbs, the Venetians, and the Ottomans, with most of the old city's present charming appearance owing to buildings constructed during the four centuries of Venetian rule. The medieval city is encircled by a 4.5 km wall 20m high that ranges in thickness from 2 to 16 metres. Wandering through the old town's labyrinth of cobblestone streets or ascending the fortified ramparts to Castel St John is delightful. The French occupied Kotor for most of the 19th century, followed briefly by the Austrians and then, in 1918, the city became part of Yugoslavia. In 2006 the Montenegrins voted for independence from Serbia, marking one of the final acts in the disintegration of the former Yugoslav Republic and establishing one of Europe's youngest nations.

Kotor's fortifications are quite possibly the world's best surviving example of medieval Venetian defensive architecture, which the United Nations recognised by inscribing the old town on UNESCO's World Heritage list in 1979, the same year that much of Kotor was damaged by a M=7.1 earthquake that nucleated on the frontal thrust about 60 km south of the bay. Since 2001, the European Commission has funded restoration efforts, resulting in today's charming tourist destination. For a stunning bird's-eye view of Kotor, drive the 'ladder of Kotor', a paved road that ascends 25 hairpin bends up the karst-riddled limestone mountain behind the town, topping out at a 1,100m pass.

Rugged Islands and a Roman Palace: Central Dalmatia

The southernmost Dalmatian islands rise just north of Dubrovnik. One of the most enjoyable aspects of exploring the Dalmatian Coast is discovering each island's distinctive character and history. Mljet, the southernmost major island, is one of the least developed and most relaxing. One attraction, courtesy of karst, is Odysseus's Cave, which is a popular swimming spot. Its name stems from the claim that this is where Odysseus was shipwrecked and held captive for seven years by the nymph Calypso.

North of Mljet lies Korcula island, famous for its wine and its dense pine forests. You can get there by ferry direct from Dubrovnik or access it along the coastal road north from Dubrovnik, from which you are treated to spectacular island views, especially at sunset. Fifty km north of Dubrovnik, the route to Korcula traverses the narrow Peljesac Peninsula, which exudes an island vibe without the hassle of a ferry ride. Slowly driving or biking the scenic, 57 km road between Ston and Orebic, the peninsula's two main towns, stopping at vineyards along the way is a real treat. A half-hour ferry ride from Orebic deposits you in Korcula town, nicknamed 'mini-Dubrovnik' because its medieval walls and orange tile roofs have the same charming ambiance.

The delta of the Neretva River, the largest to reach the sea between Dubrovnik and Split, the next major town to

The Bay of Kotor.

the north, lies a further 41 km up the coast. It is well worth the 54 km-long detour up the Neretva, crossing into the country of Bosnia and Herzegovina to visit the town of Mostar. Unfortunately, Mostar's fame lies with the suffering its inhabitants endured during the breakup of Yugoslavia. The town's namesake bridge, the Stari Most (old bridge), was destroyed in the fighting. When the arch bridge was built in 1557, under orders from the Ottoman sultan Suleiman the Magnificent, it had the world's longest span. The sultan threatened its architect, Mimar Hayruddin, with death if the bridge collapsed, so Hayruddin is said to have planned his own funeral on the day the bridge was finished. But the elegant limestone span held until 1993, garnering fame among travellers for its beauty and functionality. Reconstruction of the bridge in the original style was completed in 2004, providing a platform for cliff divers who perform the 24m leap into the river for tips. While in the area, don't miss the Vrelo Bune spring, one of Europe's largest, 7 km south of Mostar. Here, 30 m^3/sec of water pours out of a cave at the base of a limestone cliff, with an attractive, architecturally simple, Sufi monastery nestled next to it. This serene spot feels well off the beaten tourist track.

Vrelo Bune spring and monastery.

Hvar is the island of choice for well-heeled sailors, who moor their yachts in the Stari Grad (old town) harbour. Stunning views of the harbour and nearby islands can be had from the 16th-century, Venetian-built citadel above town. You can visit Brač, Dalmatia's largest island, from Hvar or on a one-hour ferry ride from Split. The southern Brač town of Bol boasts Zlatni Rat, one of the country's best white sand beaches; most Dalmatian beaches consist of cobbles, because limestone isn't conducive to producing sand-sized detritus. Brač is most famous, however, for its gleaming white, coarse-grained limestone. Highly prized in the building trades, Brač limestone was used to construct many important buildings, from Diocletian's Palace in Split to the White House in Washington, D.C.

With a population close to 200,000, Split is Dalmatia's largest city. The city's main attraction is Diocletian's Palace, the sprawling retirement home of the Roman emperor. Diocletian abdicated the throne in 305 CE, the first Roman emperor ever to do so. Palace highlights include the cellars, the peristyle, and the cathedral of Saint Domnius. The cavernous cellars are one of the world's best-preserved examples of ancient underground architecture. Diocletian's quarters opened onto the peristyle, a column-lined central courtyard. Many of the pillars are made of local limestone, but Diocletian, who developed a fondness for Egyptian art during military campaigns he waged there, also imported columns of Egyptian granite, as well as a sphinx carved from jet-black gabbro.

Karst's Magnum Opus: Northern Dalmatia

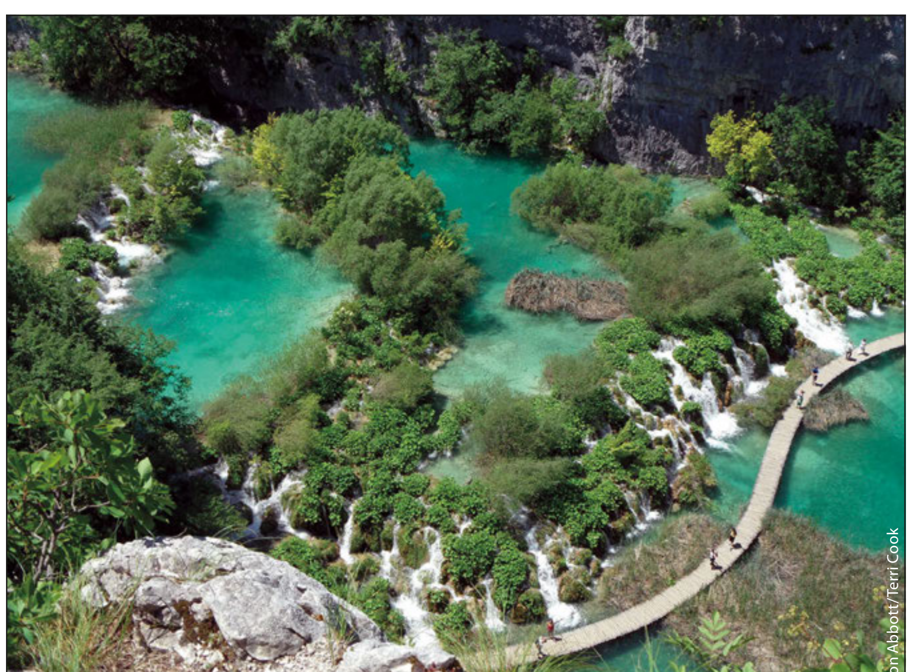
Dalmatian karst geology reaches its scenic crescendo northwest of Split, thanks to the greater abundance there of water, with its power to dissolve and reprecipitate limestone. The stunning Skradinski Buk waterfalls cascade over travertine ledges precipitated out of the carbonate-saturated water of the Krka River just off the main E65 highway about 100 km northwest of Split. They are the lowest of seven travertine waterfall complexes in the Krka National Park. The lower 23 km of the Krka River, downstream from Skradinski Buk, was drowned by sea level rise after the last glacial maximum, forming another long Dalmatian ria.

The area between Split and Zadar is topographically subdued by Dalmatian standards, with the highest peaks not quite reaching 500m elevation. That changes north of Zadar, where the 1,600m peaks of the Velebit mountains, Croatia's most extensive range, crowd the coastline. Two national parks preserve the most dramatic portions of this range: Paklenica National Park is famous for rock climbing on sheer limestone cliffs and for its more than 115 caves, including regular tours of the Manita Peć show cave. North Velebit National Park boasts Croatia's deepest cave, Lukina Jama, at 1,431m deep. It is also a hiking paradise. Premužić's Trail, named for the man who built it in 1933, is the most popular, thanks to the impressive views it affords down to the northern Dalmatian islands along its 57 km-long meander across the karst plateau. The walk gives hikers a top-of-the-world feeling despite its gentle inclines.

As beautiful as all these parks are, it is Plitvice (PLEET-veet-say) Lakes National Park, 120 km inland (and so not in Dalmatia proper), that boasts Croatia's most magnificent karst scenery. Plitvice is best known for waterfalls that tumble over travertine dams into emerald and turquoise pools, with water so clear you can see scores of fish darting in its depths. Plitvice's abundant travertine dams form where slight agitation of the water promotes the escape of dissolved carbon dioxide. That loss reverses the chemical reaction that dissolved the limestone in the first place, causing calcite to precipitate out of the water as travertine. Bacterially mediated chemical reactions assist in the precipitation. The addition of new travertine slowly modifies each lake and waterfall, continually reshaping Plitvice's ever-changing vistas.

A sombre aspect of Plitvice's history is that it was here, on Easter Sunday 1991, that the first shots were fired in Croatia's War of Independence from Yugoslavia, resulting in the war's first fatality. Here, as in Mostar and Dubrovnik, monuments memorialise those who perished in the strife triggered by the dissolution of the former Yugoslavia. Although the people of Dalmatia still carry scars from this recent conflict, they welcome visitors with open arms and a broad smile. They are proud to show off their picturesque homeland. Once you've traversed this land where karst meets the coast, you'll see clearly the source of their pride, and you'll most likely be planning a return visit before you've even departed. ■

Plitvice's travertine dams.



The Winning of Romanian Oil

Geopolitically important as an oil producer for a century, Romania remains one of Europe's largest producers.

M. QUENTIN MORTON

Oil was first exploited commercially in Romania in 1857 and, since then, the industry has seen cycles of boom and bust, prosperity and decline. One of the main factors in these events was the geographical location of the country, situated on the eastern side of Europe with access to the Black Sea and within the competing orbits of Russia, Turkey and Germany. Romanians have a proud technological and geological record in the oil industry, but international rivalry brought a troubled narrative to the story of their land.

Although the border areas of Romania were considered promising, it was a 45- by 15-mile area on the south side of the Carpathian Mountains in the vicinity of Ploesti that became the main producing area. The oldest oil fields of Campina and Bustenari were discovered close to the mountains on thrust-faulted anticlines, while other larger fields such as Moreni and Baicoi were found on anticlines with exposed salt cores. These discoveries brought geologists from across Europe who carried out stratigraphic and structural studies of the country, as well as attracting the interest of oil companies of the wider world. Illuminated by oil lamps, the capital Bucharest was known as the 'Paris of the East'.

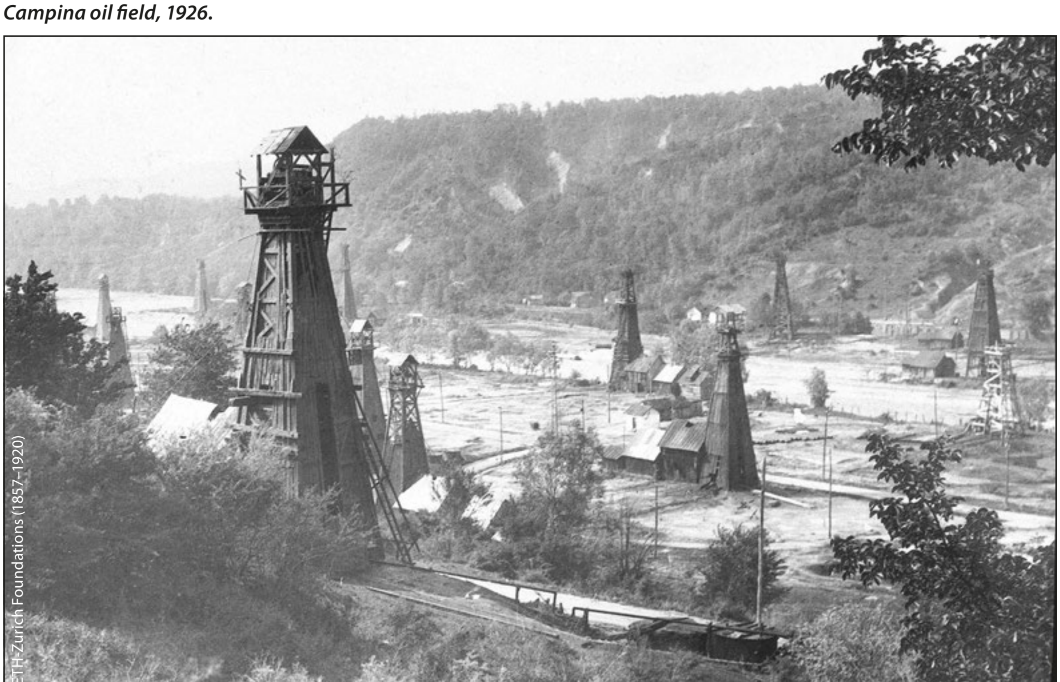
In 1895 a mining law allowing the investment of foreign capital was passed, leading to an influx of companies from abroad. The Bank of Hungary founded Steaua Romana, which was to become a mainstay of the industry. The following year Standard Oil of New Jersey (Jersey Standard) formed Romano Americana and bought leases in the Moreni field. In 1903 Deutsche Bank representing German interests reorganised Steaua Romana after it went bankrupt. In 1905 British, French, Belgian and Romanian firms were involved in the industry, followed by Royal Dutch Shell, which created Astra Romano in 1908 and took over the larger Regatul Roman. Two years later, this company was the leading producer in the country, accounting for some 3.8 million barrels of oil.

The pre-WWI oil industry was in many ways a showpiece of technology and geology, counting the invention of the blow-out preventer among its achievements. However, Romania was a rural economy and the principles of agrarian land distribution held sway, with ownership in many oil-rich districts divided between small strips of land. By 1905, a team led by Professor Ludovic Mrazec of Bucharest University, the first Romanian geologist to support the organic origin of petroleum, had mapped the country and identified suitable sites for testing; but there were many land speculators asking for inflated prices and, when British geologist Arthur Beeby-Thompson visited Romania, he found that many oil wells were still being dug by hand.

Nevertheless, the country was a rising star in the petroleum world. By 1915, the industry was in the hands of 94 companies, with foreign interests owning about 95 per cent of production. But when Romania declared on the side of the Allies in 1916, the British requested the government to destroy its oil installations in order to deny them to the advancing Germans and more than 1,500 wells were plugged and 70 refineries destroyed. 'The Romanians, under English orders and directions, had effected a very thorough destruction of the oilfields', observed German general Erich Ludendorff. Oil production dropped by three quarters, although geologists from Steaua Romano were able to assist in restoring some output to the oil fields.

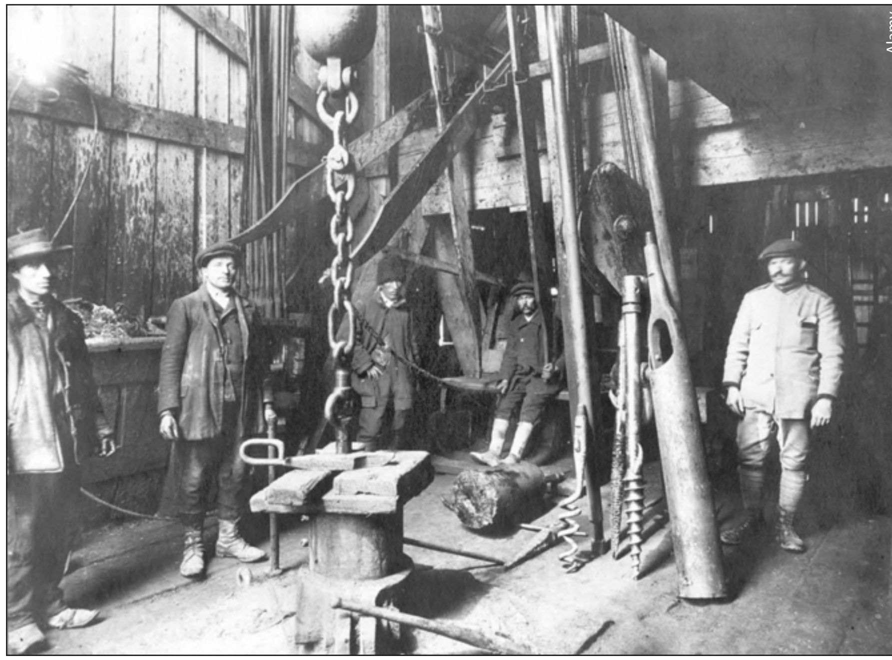
After the Germans withdrew in 1918, the wells and refineries were repaired, but a sluggish recovery in Europe meant that demand for Romanian oil was low and another six years would pass before production regained its pre-war levels.

Campina oil field, 1926.



ETH-Zurich Foundations (1857–1920)

Nevertheless, the country's reputation endured: in 1920, it was observed in a British government report that 'Romanian methods of winning oil are at the present time second to none.'



Workers inside a pump jack installation in the Romanian oil fields, 1917.

Great Power Rivalry (1920–1939)

'Imagine hundreds of gigantic oil derricks, black toothpicks as tall as a ten-storey building reared up on the plain. Back of them picture mighty mountains cutting the sky, and in front the grain-laden lowlands through which the Danube is flowing to the sea', American writer Frank Carpenter wrote of the Moreni-Tuicani oil field in 1923. Apparently Dr Nerasic, head of the Geological Institute, had predicted there was so little chance of finding oil at Moreni that he would drink every quart of it. No doubt, like Dr G.M. Lees who promised to drink every drop of oil found in Bahrain, Nerasic rued his words. Romania ranked sixth among the oil producers of the world, and Jersey Standard had invested over $20 million there.

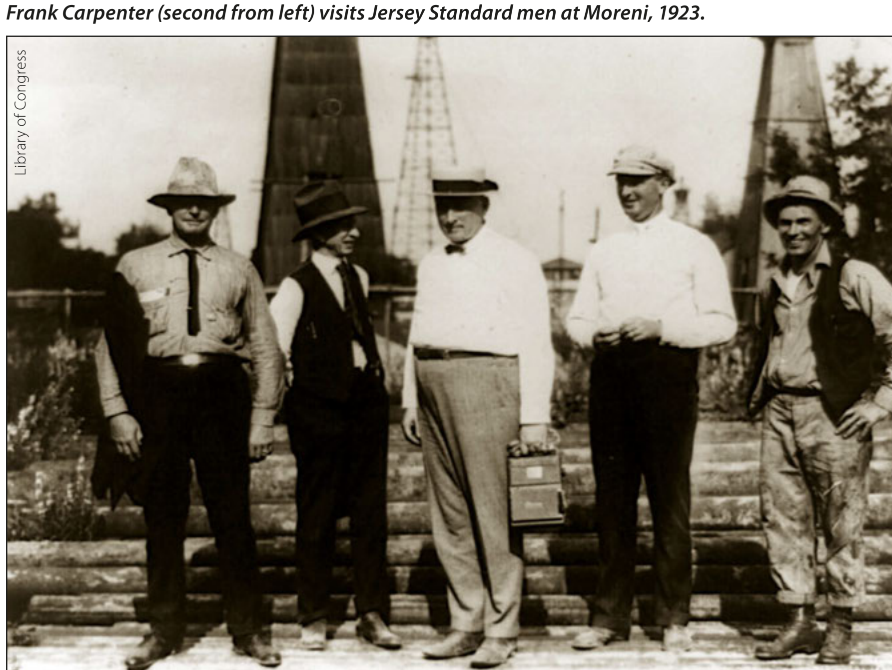
This was a critical time. The government was attempting to address the foreign domination of its oil industry by nationalising the mining subsoil, although 'gained rights' were protected. The new law brought new problems such as competitive drilling on small tracts, speculators and petty bureaucracy, but engineering methods improved and production increased. Another mining law in 1929 restored the rights of foreign investors by putting them on an equal footing with Romanians.

External factors buffeted the industry: the world was suffering a glut of oil with new supplies, especially cheap oil from Russia. Attempts by the oil barons of the West to control oil prices failed, and the Wall Street Crash left those companies with weak finances struggling to avoid bankruptcy. A massive well fire in the Moreni field, the so-called 'Torch of Moreni', burned for over two years before it was extinguished by the American firefighter, Myron Kinley. And yet, despite these troubles, Romanian oil production continued to grow.

At the heart of foreign interest in Romania was a realisation that oil was crucial to future military success. The spectacle of French soldiers in WWI being transported to the front line in Parisian taxis after their railway system had failed was not forgotten; but American oil was susceptible to attack from German submarines, and the French needed a reliable source of oil closer to home.

Romania was the obvious choice, with transport routes available through the Danube, Black Sea and Mediterranean. Having gained a share of the forfeited German oil holdings as the spoils of war, the French oil industry grew and prospered. Together with their British and Romanian partners, they helped to put Steaua Romana back on its feet. It was a valuable training ground for future executives of Compagnie Française des Pétroles (the forerunner of Total), and for their subsequent dealings in the oil business. Several French managers learnt their trade in production, refining, marine shipping and marketing in the oil fields of Romania.

Frank Carpenter (second from left) visits Jersey Standard men at Moreni, 1923.



A well fire at Moreni ('Torch of Moreni') in 1926.

Having also relied on American oil supplies during World War I, Great Britain focused on developing its petroleum interests in far-flung lands, notably Iraq and Iran, and showed little diplomatic interest in Romania, although British capital and technical expertise were still involved there. However, the French, despite their early interest, failed to capitalise on their position, and a slide into the German orbit seemed inevitable, particularly when France fell to Germany in June 1940.

World War II (1939–1945)

Since Germany's crude oil reserves were meagre, waxy and unsuitable for motor and aircraft fuel, it relied on home-made synthetic oil and imports from Romania and Russia to make up the shortfall. The militarisation of Nazi Germany brought a powerful spotlight onto Romanian oil, for German control of the Romanian fields was vital for success in the coming war, especially if supplies from Russia ceased. And so Germany became Romania's most important trading partner, accounting for almost 40 per cent of its exports in 1938.

At the start of the war, Romania reached an agreement to allow Germany access to its economic resources but remained neutral. There was a strange sense of being out of the war but also a part of it: British and French diplomats carried on their business in Bucharest as Swastika-flying barges plied the River Danube with cargoes of oil for the German war effort. Behind the scenes, the British planned an ambitious scheme to fly 400 troops on Bristol Bombay aircraft from the Middle East and land them in the Ploesti area to sabotage the oil fields, but the idea was, perhaps fortunately, abandoned.

As Allied relations with Romania deteriorated, foreign employees were expelled from the oil fields, which fell increasingly under German control. Romania took the last, fateful steps to war in September 1940 when a right-wing coup brought Fascist prime minster Ion Antonescu to power and Germany invaded the country a month later. Ominously, a massive earthquake damaged the oil refineries at Campina and the pipelines between Ploesti and Constanta, although a German technical commission quickly effected repairs. In June 1941 Romania took part in Hitler's invasion of Russia but, when the offensive fell short of the Baku oil fields, Germany's dependence on Romanian oil was sealed.

The point was not lost on the Allies. At the Casablanca Conference in January 1943, Roosevelt and Churchill agreed a joint bombing strategy to destroy the Romanian oil fields 'by air bombardment'. At the beginning of August, 'Operation Tidal Wave' saw 178 B-24 Liberator bombers attack Ploesti, but the results were disappointing. Fifty-four aircraft were lost and only limited damage was inflicted on the oil installations, which soon resumed production. Despite follow-up raids, the Allies never managed to choke off oil supplies to Germany. That would take

German soldiers operate an anti-aircraft gun at Ploesti, 1941.

a monarchist coup d'état and Romania switching sides in August 1944.

After the war, the industry fell on hard times. The Russians seized much of Romania's petroleum equipment as war reparations. Foreign companies returned in 1945 to a country with a communist regime, which nationalised the industry in 1948; the managing director of Romana Americano was imprisoned and the general manager fled the country.

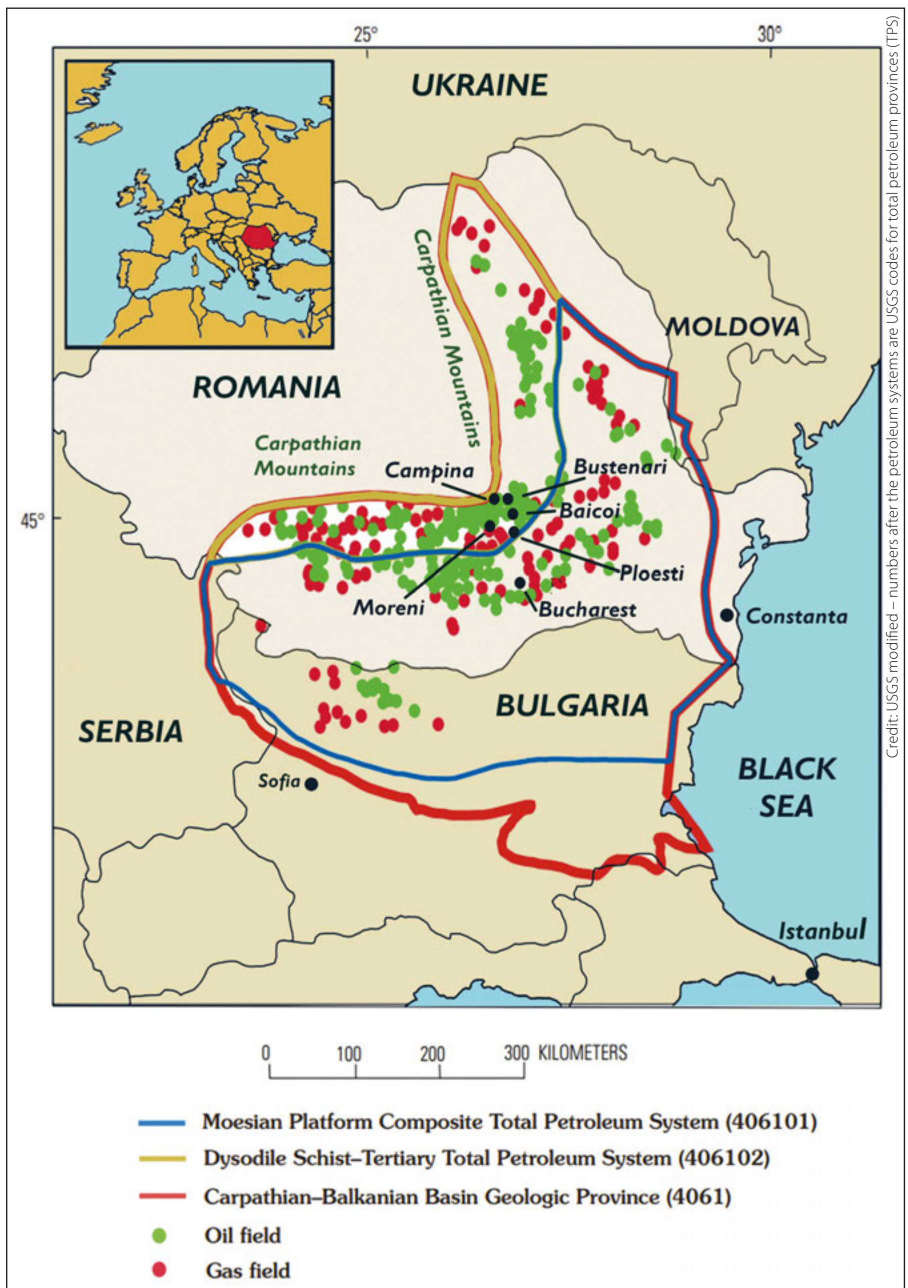
To the Present Day

For the next ten years, the Romanian oil industry was geared towards the needs of the Soviet Union. Although a new enterprise, Sovrompetrol, was set up as a joint Soviet–Romanian venture to control the industry, the bulk of oil production was diverted to Russia. It was only with the death of Stalin and the advent of Khrushchev's policy of de-Stalinisation that full control of the oil industry was returned to the Romanian government. Released from the petty bureaucracy of the pre-war years, the industry saw a revival of exploration and the discovery of new fields. Oil production peaked at 15 million tons in 1976, and the first exploration well in the Black Sea was drilled, but output thereafter went into decline. The revolution of 1989 brought an end to communist rule and a move towards a free-market economy.

Today, Romania's oil policies reflect the lessons of the past by seeking energy independence. The country is the third-largest oil producer and has the fourth-largest crude oil reserves in Europe with 600 MMbbl of proven reserves as of January 1, 2014. It has nine refineries with a total capacity of 467,642 bopd, giving it among the largest refining capacities, although oil production has continued to decline, with total production of crude oil and other liquids dropping from 134,000 bopd in 2003 to 104,000 bopd a decade later. Meanwhile exploration continues with 3D seismic acquisition revealing prospectivity in structurally complex areas, such as the Carpathian Bend Zone, and recent gas discoveries in the deep waters of the Black Sea are highly promising.

Acknowledgements: Thanks to Peter Morton for his kind assistance. ■

Oil trucks on the quayside at Constanta, Romania, 1936.



The Carpathian–Balkanian Basin Province, Romania and Bulgaria.

The West of Shetland Petroleum System

Is it that complex?

J. MOORE, APT UK; and
Z. HE, Zetaware Inc

A top-down and bottoms-up approach to petroleum systems analysis is considered to illuminate some important concepts. The top-down approach relates to the interpretation of fluids and their distribution in the geological and pressure-temperature contexts to constrain the petroleum system and to infer the location and properties of yet-to-find hydrocarbons (He and Murray, 2019). Whereas bottoms-up methods typically utilise empirical, physical, and chemical models of the processes that occur in sedimentary basins to predict timing of generation, migration and the trapping of petroleum in the subsurface.

The earliest publications on the petroleum systems and basin modelling in the West of Shetland concluded that oil generation from the Upper Jurassic occurred in the mid-Cretaceous due to rapid Cretaceous basin subsidence (Holmes et al., 1999). This timing precedes the deposition of the proven Palaeocene and Early Eocene reservoirs and seals and thus the area has been considered complex. Critical aspects of the geology that are important to consider when modelling the petroleum system include the impact of pressure and 'moteling' (i.e., the retention of petroleum at depth), age and composition of the basement, influence of Tertiary volcanism/intrusion, Late Tertiary uplift and the influence of migration lag effects. Additionally, some published assertions reflect a fundamental misunderstanding of source rocks and what they expel through time, which has led to incorrect perceptions of the petroleum system. While aspects of the geological evolution may still be complex, the distribution of phase (oil vs gas) is not and can be accounted for by the expected physical behaviour of petroleum in the subsurface.

Basin Modelling and Phase Risk

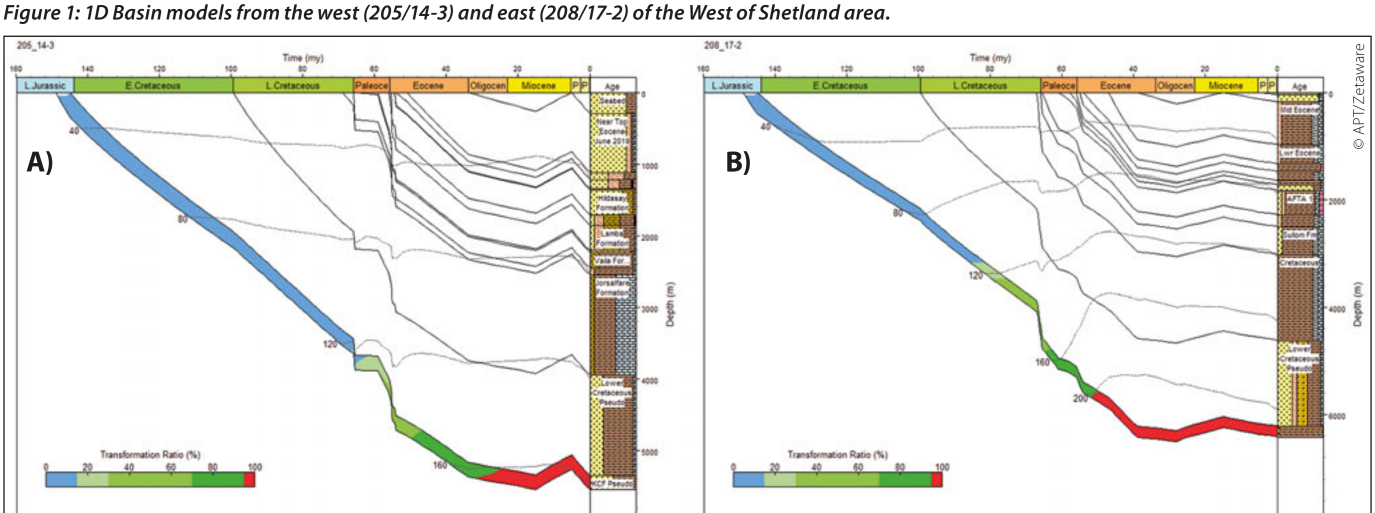
While we expect that basin models have been relatively successful in temperature and pressure prediction, their success in preventing dry holes and in phase-prediction is modest at best. He and Murray (2019) have discussed this challenge and conclude that the models used do not replicate nature, so this should not be surprising.

At the basin scale, systems tend to fall into either gas-prone or oil-prone and this overwhelmingly relates to the nature of the source rock. In basins with discoveries, a 'system' gas–oil ratio (GOR) can be estimated. For the West of Shetland, if we estimate ~10 Billion bbls of oil in place in the proven oil discoveries and similarly ~18 Tcf GIIP in the associated gas and in the known gas fields, then the system GOR would equal 1,800 scf/bbl, which is consistent with a Class B marine, oil-prone source rock (Pepper and Corvi, 1995).

A common misunderstanding is that gas-mature equates to dry gas or a gas risk. 1D models (Figure 1) or basin model derived maps will often be made in a basin model with some parameter (% vitrinite reflectivity (Ro), standard thermal stress, transformation ratio etc.) and then inferences about the predicted phase made based on the map, and these maps may even be used to describe a 'phase risk'. Explorers may look at basins with deeply buried source rocks and erroneously pronounce them 'gas-mature'.

Does high maturity really relate to 'high maturity' gas? The answer is no. In Figure 2 the model shows that in an oil-prone source rock that has efficient expulsion, ~80% of the mass will be converted to black oil (gas/liquid ratio <2,000 scf/bbl); even in temperatures commonly referred to as the 'gas window' the product will be volatile oils to rich gas-condensates with

Figure 1: 1D Basin models from the west (205/14-3) and east (208/17-2) of the West of Shetland area.



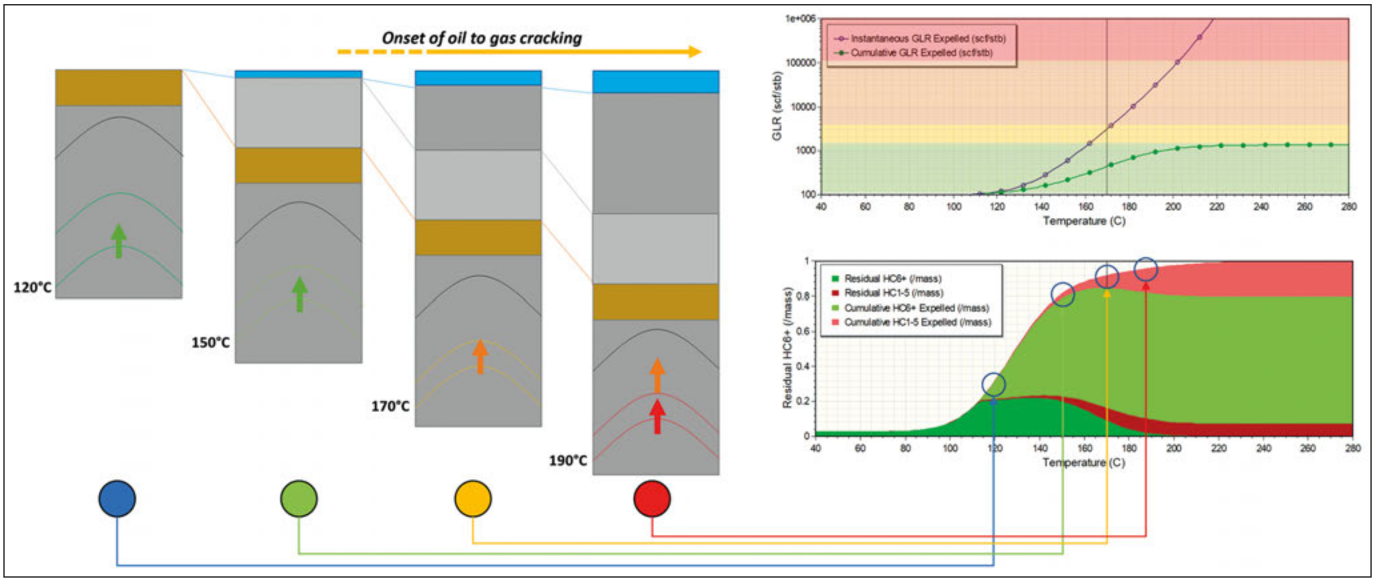


Figure 2: Oil generation and expulsion in a Class B marine source system under typical geological heating rates, illustrating how, in the cumulative expelled and residual C1–C5 (gas) and C6+ masses about 80% of the mass is converted to oil (C6+) and the cumulative GLR (the sum of the expelled product) will be <2,000 scf/bbl.

wet gases probably only being dominant at (source rock) temperatures ~190°C and above.

It seems likely that even after the source rock is effectively exhausted, significant secondary migration will occur. Where oil is retained at depth, either in inter-bedded units in the source rock or in traps too deep to drill, oil will eventually crack to condensate and wet gas which may continue to contribute to the volume available for migration (due to volume expansion) (Figure 3).

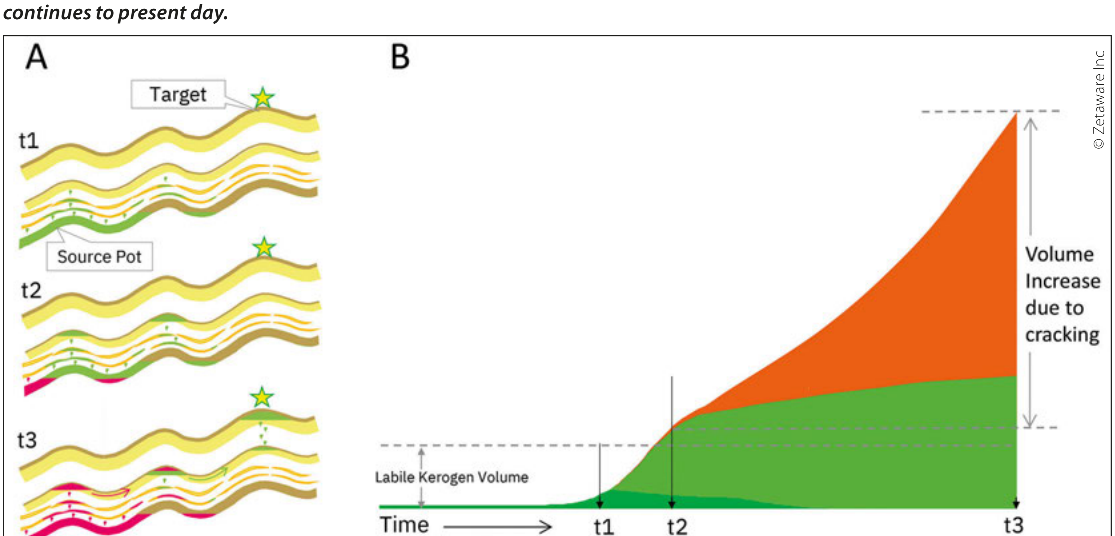
In this sense, deep basins, with an oil-prone source rock are most favourable from an exploration point of view since they will have the greatest mass of petroleum available for migration (Gulf of Mexico, Central North Sea). 'Moteling' is commonly dismissed by explorers as a form of special pleading. Logically, however, if you are exploring for traps within a basin, it seems illogical to dismiss the occurrence of traps at depths beyond those in which we typically explore.

Top-Down Assessment

The West of Shetland has been thought of as enigmatic since the published basin models predicted that the source rock was in the oil window near the end of Cretaceous, and post-mature today – even if using correctly parameterised basement (cf. APT and Chemostrat, 2020; Gardiner et al., 2018). Yet the basin contains mainly oil fields and is certainly more oil- than gas-prone in mass terms. A rough estimate of the system GOR is less than 2,000 scf/bbl, consistent with the Pepper and Corvi (1995) Class B organo-facies and yet areas have found gas, so how to make sense of the basin? Do the models and observed fluids agree?

In a system with oil-prone source rocks, the bulk of the product will be oil and hence most of the accumulations should be oil, regardless of maturity or timing. The GOR and API gravity of the oils should increase with depth for various reasons, such as migration lag effects, gravity fractionation, and bubble point controls. Simply plotting this data can bring significant insight to the petroleum system. The gas–oil ratio versus saturation pressure is plotted in Figure 4A, and reservoir pressure in Figure 4B for most

Figure 3: Total Hydrocarbon Volume in Subsurface Conditions. At time t1 (mid oil window): source rock is saturated, and oil begins to fill adjacent carrier beds. t2 (end oil window): gas generation and cracking of oil begins. Migration front advances. Intermediate traps in carrier beds are being filled with oil. Through to present-day t3: continued increase in volume due to successive cracking of retained oil to lighter oil and gas in the source rock and adjacent carrier beds. Secondary migration continues to present day.



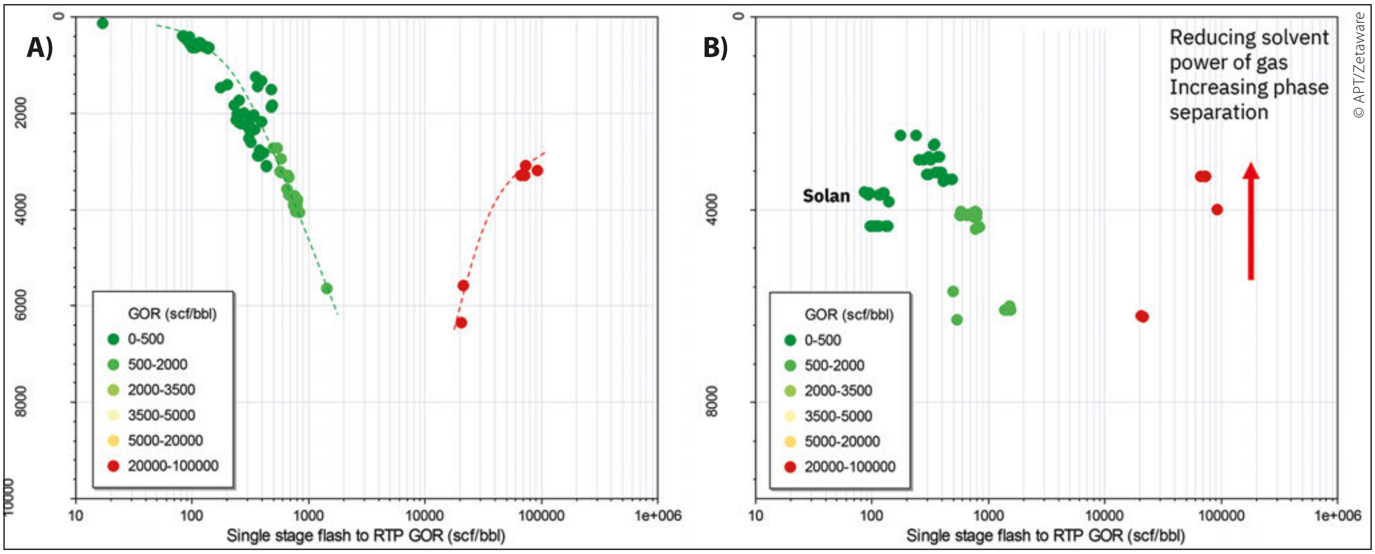
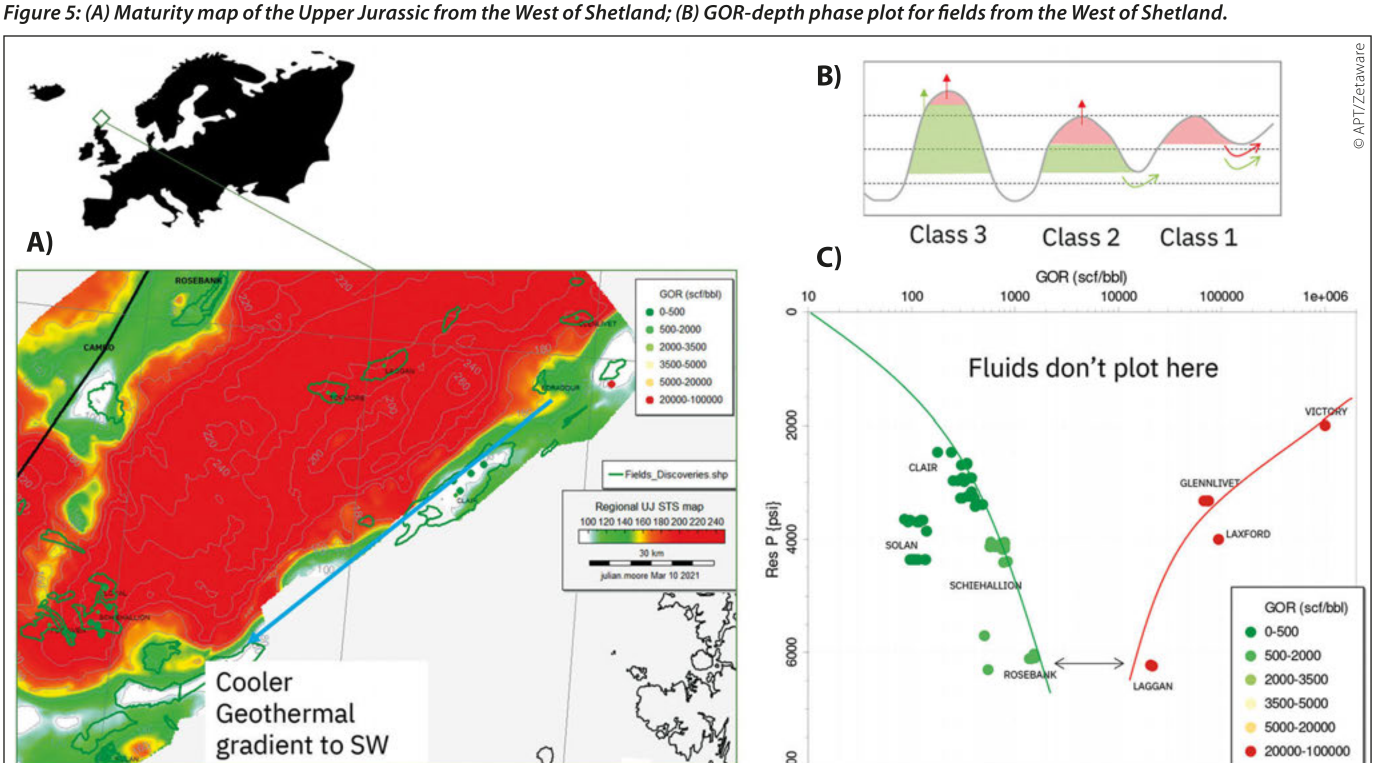


Figure 4: Plots of PVT from the West of Shetland showing Gas–oil ratio against (A) the saturation pressure (psi) and (B) the reservoir pressure.

of the fields from the West of Shetland; this shows most of the fields are black oils close to their saturation pressures.

A maturity map for the Upper Jurassic is shown in Figure 5a. Inspection of the burial histories (Figure 1) might suggest that the basin migrated oil in the Late Cretaceous and would be dominated by gas present-day, but exploration results has proven otherwise. To date, much of the exploration focus has been on the shallower, post-rift plays because of the known challenges for seismic imaging (due to widespread volcanics) that have historically hampered the targeting of the deeper syn- and pre-rift plays. West of Shetland fields are generally hydrostatic with reservoir pressures close to saturation pressures and hence gas caps are likely to form. In light of this and the observations that the gas fields are small relief structures and oil fields have large closures, the distribution of oil vs gas can be explained by the Sales 1997 model of trap classes (Figure 3A). Small gas fields are a result of phase separation, rather than maturity, and the GOR for those are higher at shallow depth due to dew point control. Small traps located on a spill path will retain phase separated gas by spilling its oil leg (class 1), whereas large relief structures should contain oil (class 3), the preservation of the oil leg is a function of the seal capacity and the depth to the spill point not maturity. Thus, in the case of the Clair field, which both leaks gas and has a deep spill point, the potential exists for the oil to be preserved. The greater buoyancy of gas and leaky seals act to preserve the oil legs (Figure 5b). Most of the main oil fields West of Shetland are two-phase (e.g., Clair, Foinaven,

Figure 5: (A) Maturity map of the Upper Jurassic from the West of Shetland; (B) GOR-depth phase plot for fields from the West of Shetland.



Rosebank etc.) suggesting similar processes are occurring in each. While conceptually simple, these processes can be complex to capture in a model.

Concerns expressed around the timing of generation are perhaps moot, since valid traps tested by drilling are proven to be charged. An often-cited concept in petroleum systems studies is the 'critical moment', defined by Magoon and Beaumont (2003) as 'the time that best depicts the generation–migration–accumulation of hydrocarbons in a petroleum system. A map and cross section drawn at the critical moment best show the geographic and stratigraphic extent of the system'.

In the deeper parts of the basin where the Jurassic is over 7 km deep present-day, irrespective of the thermal (or pressure) model invoked, maturation will be early relative to the deposition of reservoirs and seals. Evidence of earlier charge phases exists in fluid inclusion data e.g., Mark et al. (2005) and thus cannot be dismissed entirely. Cooler geothermal gradients are known to occur in the Quad 204 area and can be accounted for based on the basement composition (cf. APT and Chemostrat, 2021), which will act to retard the timing of generation relative to models with standard properties. Furthermore, it seems likely that there will be some degree of 'migration lag' induced by the geologically temporal storage of oil at depth, which either becomes available through leakage or is cracked to lighter, more mobile compounds (Figure 3). Quantitative estimates of the degree of 'lag' are challenging to determine with confidence; in the Gulf of Mexico, another basin dominated by oil but with a very deeply buried source rock, He (2016) estimates a migration lag of 10–20 Ma and similar values may also be appropriate for the West of Shetland.

Maturity, Phase and the Critical Moment

There are commonly held misunderstandings in the industry regarding how maturity relates to phase. This article provides a clearer framework with which to consider how phase may be distributed within a basin. For accurate phase prediction, integration across the following elements is required: charge volume and GOR, trap pressure, trap geometry and seal capacities. This has not always been adequately captured in basin models, however tools are becoming available that allow these factors to be assessed probabilistically on the principal controlling elements, allowing geoscientists to judge the expected phase in a risk-based manner.

The Faroe-Shetland Basin's current discoveries can be accounted for by some combination of: delayed expulsion due to a function of cooler models (especially in the south-west) appropriate expulsion models; migration 'lag' and the preservation of oil legs under leaking gas caps. Given the complexity at play in such systems, the use of the 'critical moment' concept does not seem very helpful and its importance is perhaps overstated.

References available online. ■

UK Onshore Palaeozoic

OLIVER BUTTON

This article, from the second of our joint *GEO ExPro* student competition winners, focuses on overlooked onshore UK prospectivity.

A Rich History

In 1851, wide seams of organic-rich shales were discovered in West Lothian. As an innovative chemist, James Young discovered how to distil oil from shale. This fired up the industrial revolution and launched the UK oil and gas industry. By 1913, Scottish oil peaked at 6,000 bopd. Demand doubled during WWI, and the government introduced the Petroleum Act of 1918. Funded exploration for conventional hydrocarbons led to discoveries in the Midland Valley of Scotland and on the anticlinal flanks of the Derbyshire Dome.

G.M. Lees, head of exploration for the Anglo-Persian Oil Company, recommended the Petroleum Act of 1934 'under geological reasoning', and the UK onshore oil and gas industry was nationalised. At the start of WWII, D'Arcy Exploration noted minor oil accumulations within Pleistocene clays along the Lancashire Coast and the Formby Oilfield was discovered. This was soon over-shadowed by discoveries in the East Midlands, where petroleum shows within concealed coalfields in and around the Ollerton Anticline led to the discovery of the Eakring Field.

The East Midlands Province was vital for the UK during WWII, and production of hydrocarbon-bearing Carboniferous interbeds and Permian limestones continues to present day. With over 30 commercially viable fields identified, the province contains the UK's largest onshore gasfield (Saltfleetby) and second-largest oilfield (Welton).

After the war, technological advances in seismic revolutionised onshore exploration. Twenty-five deep-seated discoveries across Nottinghamshire, Yorkshire, Lancashire, and Scotland accounted for 3,000 bopd. In 1959, the UK produced 80,000 tonnes of oil from the East Midlands Province alone. The UK Continental Shelf Act of 1964 saw a boom in offshore exploration, and with tough competition from Middle Eastern imports, onshore exploration was deemed less favourable. Despite this, large Mesozoic systems were discovered in Dorset, and the Wytch Farm oil field, discovered in 1973 soon became Europe's largest onshore field.

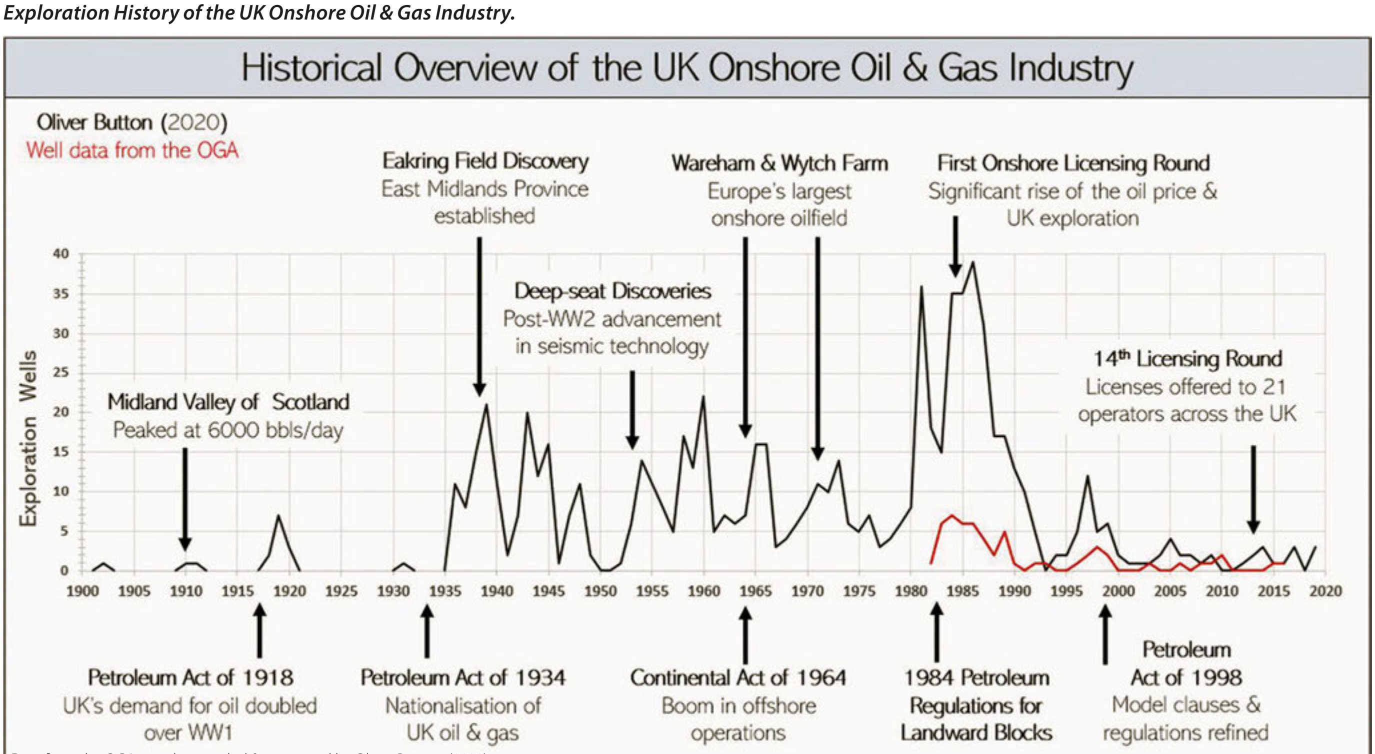
The first official onshore licensing round was held in 1985 and with an increase in UK onshore exploration and production, legislation was later revised into the Petroleum Act of 1998. By 2013, 1,800 wells had been drilled; 300 operating wells across 120 sites produced more than 20,000-barrels of oil equivalent per day.

To date, 14 onshore licensing rounds have taken place, the last in 2014 and the decision to devolve onshore licensing authority to the Scottish and Welsh ministers was made in 2018, but the 15th UK onshore licensing round is yet to be held.

Geological History and Prospectivity

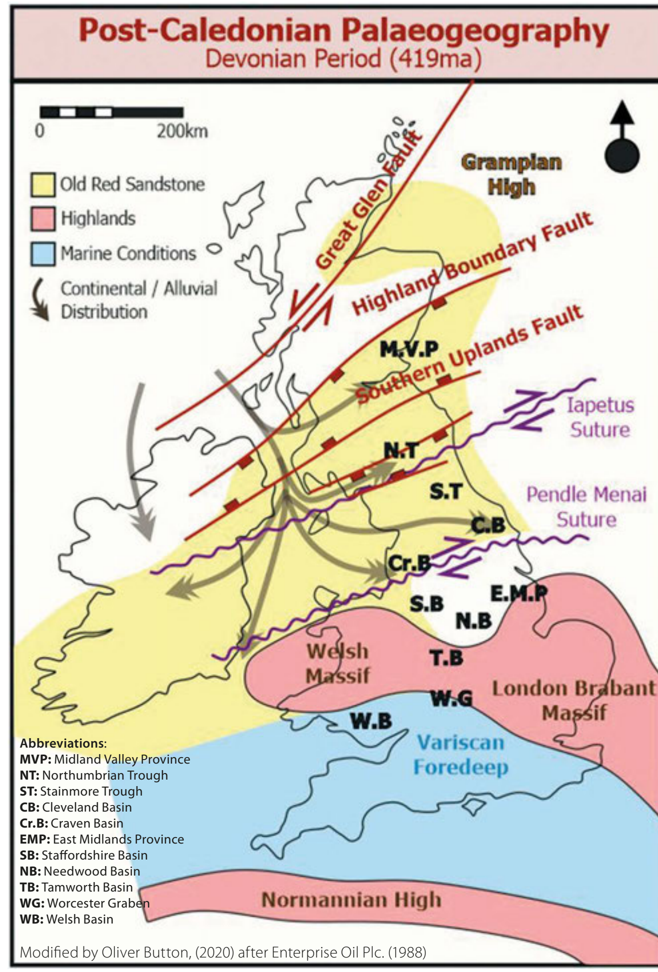
For over 490 Ma, the UK has been subjected to intense deformation, sedimentation, and re-configuration. Where technical risks commonly

Exploration History of the UK Onshore Oil & Gas Industry.



outweigh economic viability, a thorough understanding of conceptual geology is critical.

490 to 390 Ma, the 'Caledonian Orogeny' was the first mountain-building event of the UK Palaeozoic. Uplifted highlands sourced Devonian-aged 'Old Red Sandstone', packages of alluvial sand and axial rift channel reservoirs. These hot-desert-like sediments are intercalated with playa lake muds and evaporites, deposited within the subsiding depocentres of ancient continental half-grabens, such as the Midland Valley of Scotland.



Schematic UK setting for the Devonian period, 419 million years ago.

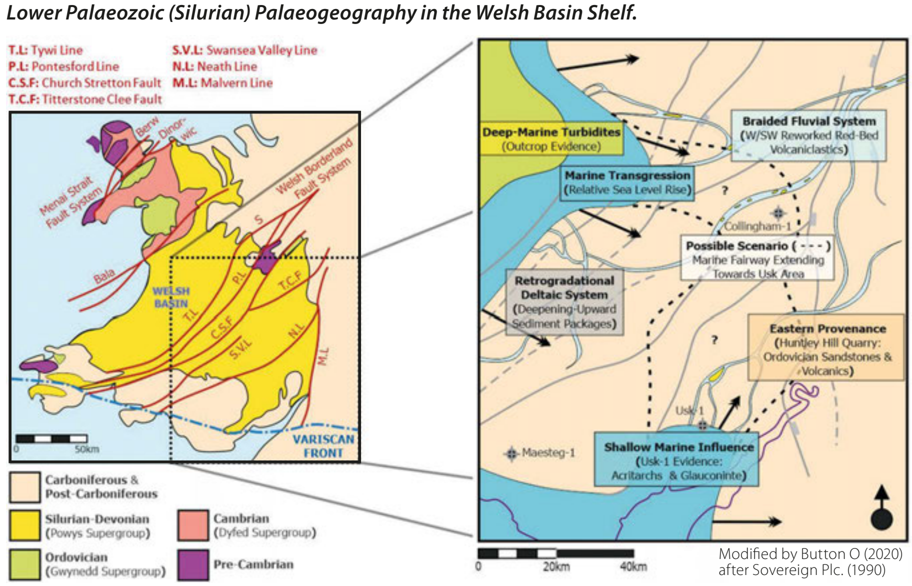
Hurricane Energy (2008, 2011) was the first oil and gas company to investigate the Strathmore Basin, Scotland. Devonian outcrops represent a series of mappable petroleum elements in the Old Red Sandstone. Regional satellite imagery and 2D seismic signalled that complex, fault-bounded traps were likely preserved and associated with the Tay Graben. Unfortunately, local noise and concerns for water supplies resulted in a low-resolution survey. Despite this, Hurricane stated: "The Strathmore Basin does support a valid Devonian play", and further exploration is recommended.

In the Lower-Palaeozoic, marine deposits become more prominent in the Variscan foredeep, south of the Welsh Massif and Midlands Micro-craton. Deep-sea organics are thought to underlie Silurian to Devonian-aged turbidites, shoreline sands, and fluvial channel reservoirs.

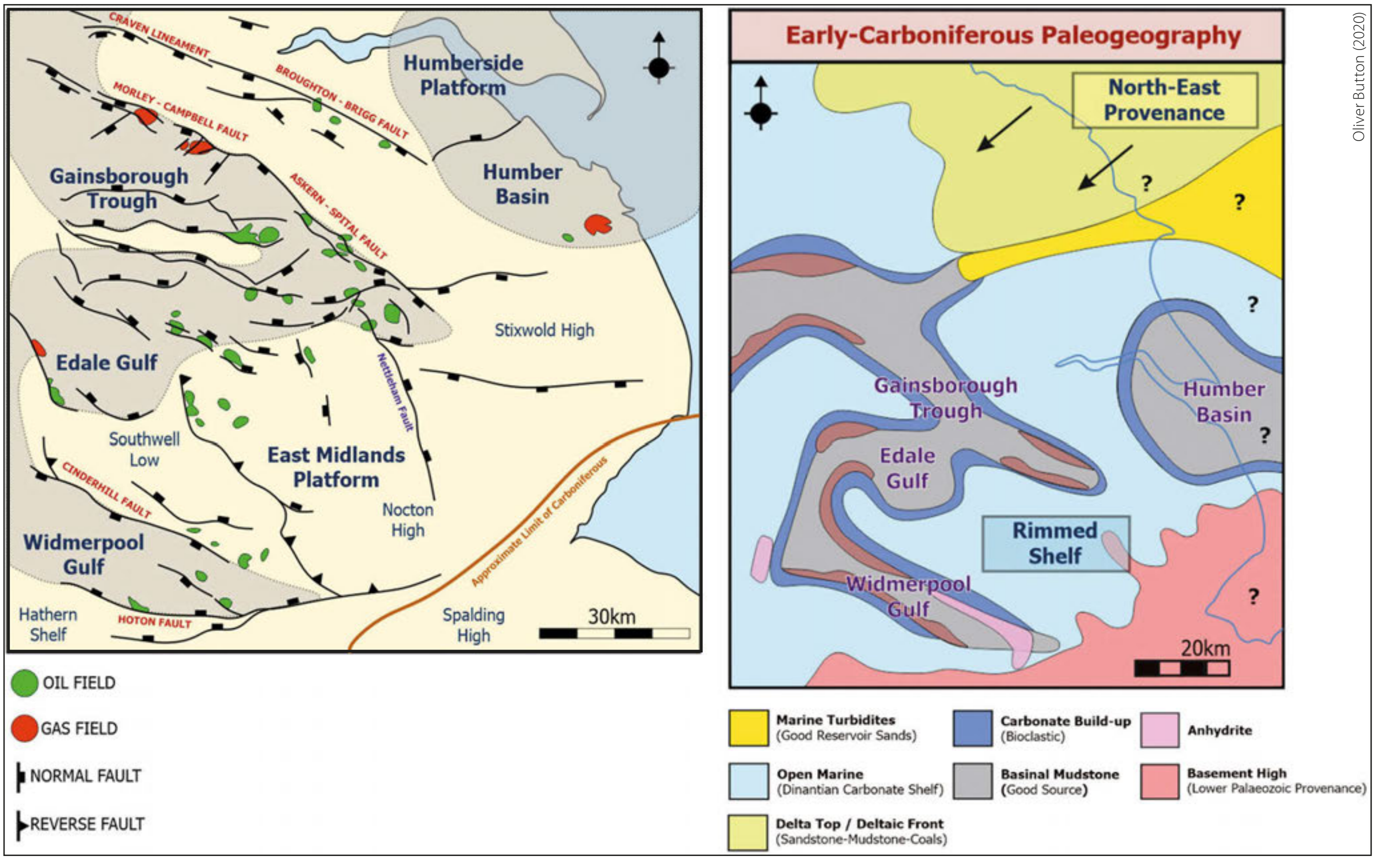
The Welsh Basin is commonly little explored, but Sovereign & Amerada Hess (1985) investigated the Woolhope and Usk anticlines along the Welsh Basin Shelf, but without success. Since then, coal bed methane has been the preferred objective. Coastal Oil & Gas (2016) hinted at the presence of natural gas within traps like those described by UK Methane (2004); however, most source rocks matured early in their geological history. Being on the forefront of the Variscan Orogeny, discoveries are likely to be degraded relics of heavily re-distributed systems.

At the onset of the Carboniferous, wrench-style tectonism developed a series of sub-basins across the UK. Many were characterised by platform Carbonates such as the Derbyshire Dome, but those in the Midland Valley were largely siliclastic. Drowned basins are represented by deep-sea organics, such as the Bowland Shale and Millstone Grit. During episodes of reduced tectonism, south-westward prograding deltas filled basinal lows with lagoonal oil shales, fluvial channel sandstones, and swampland coals; some of which are strongly tied to the onshore oil and gas industry.

Lower Palaeozoic (Silurian) Palaeogeography in the Welsh Basin Shelf.

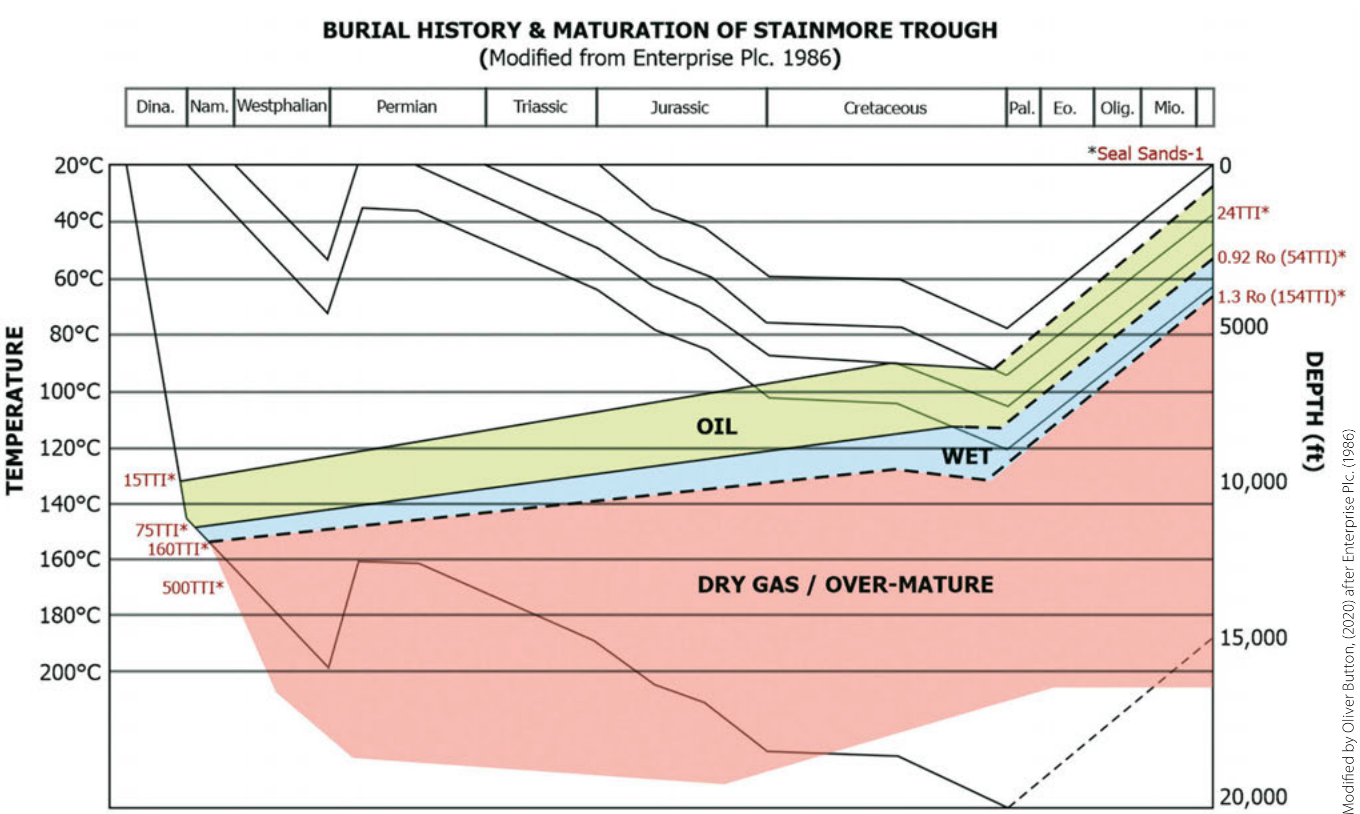


The end-Carboniferous 'Variscan Orogeny' was the second major mountain-building event of the UK Palaeozoic. Pre-existing faults were re-activated by compressional tectonics, and anticlinal traps formed. The Carboniferous-aged Craven Basin underpins proven Permo-Triassic systems such as the Cheshire Basin and West Lancashire Plain. Tilted fault blocks and Variscan anticlines are capped by end-Palaeozoic evaporites, and are thought to trap siliclastic reservoirs (British Gas & BP 1991). The Northwest Water Authority (1986) also noted prospectivity in Palaeozoic dolomites. EDP Group (2008) later conducted deep-seated exploration in this commonly overlooked basin. The Bowland Shale is regionally present across the Midlands.



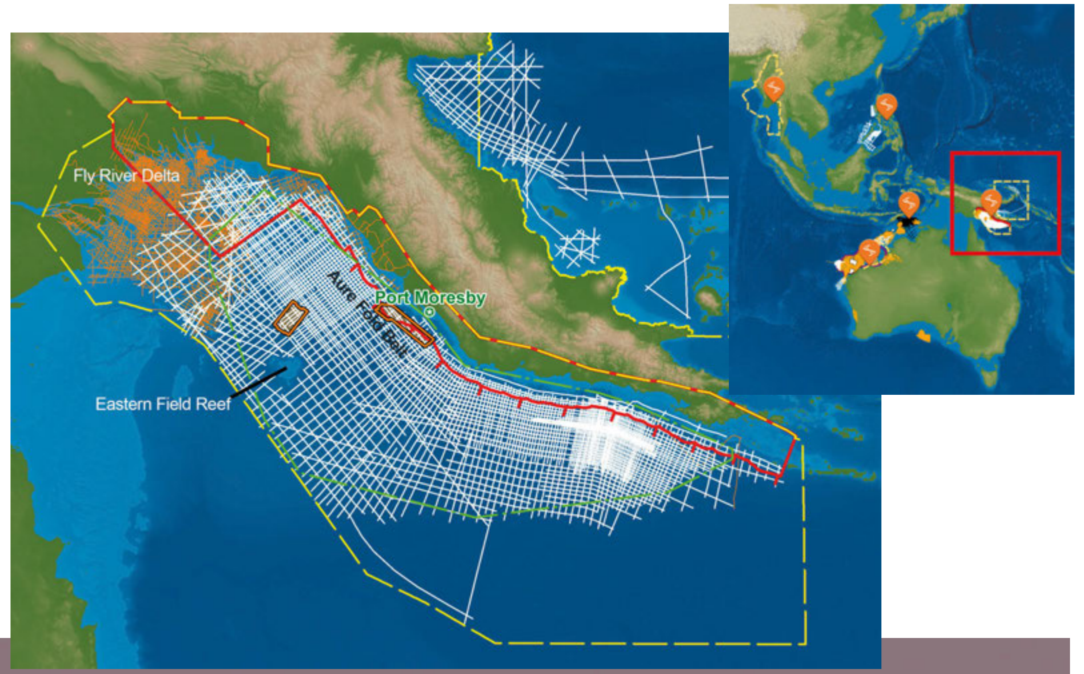
Sub-basin Structure, Occurrences, and early-Carboniferous Palaeogeography of the East Midlands Province.

High-Risk Burial History and TTI Calculation of the Stainmore Trough, north-east England.



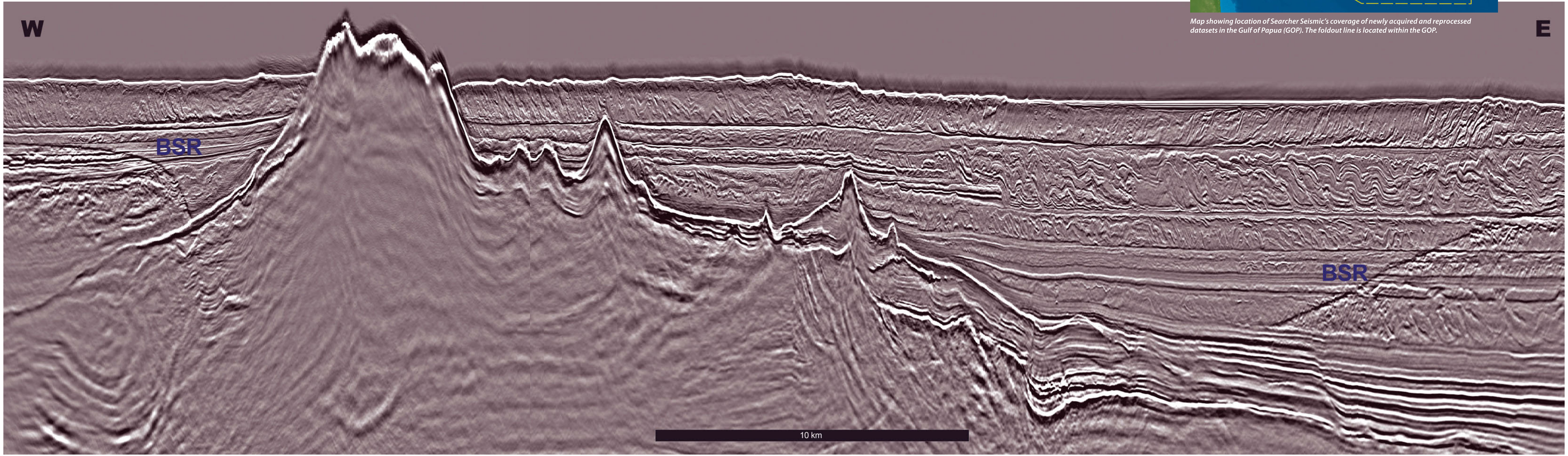
What Does It Mean When Bottom Simulators Are Black Swans?

Determining the geothermal gradient in an undrilled region has direct implications for basin modelling and remains one the largest areas of uncertainty in frontier basin exploration today. Bottom Simulating Reflectors (BSRs) occur at the base of a shallow gas hydrate layer in many of the world's deepwater basins and by calculating the geothermal gradient from the sea floor to base hydrate, quantitative and qualitative inference of the deeper heat flow can assist basin modellers in their work. However, BSRs do not always simulate the seabed and such deviant behaviour can lead them to be interpreted as 'anything but' the base of the gas hydrate. Yet such black swans suggest BSRs may be even more useful in mapping variations in heat flow and geotherm than we had previously recognised.



Map showing location of Searcher Seismic's coverage of newly acquired and reprocessed datasets in the Gulf of Papua (GOP). The foldout line is located within the GOP.

West–East Line from the Laurabada 3D located near the Eastern Field Reefs, Gulf of Papua. PSDM processed displayed in TWT.



Using Bottom Simulating Reflectors in Global Frontier Exploration

KARYNA RODRIGUEZ, NEIL HODGSON, Searcher Seismic and JULIA DAVIES, Discover Geoscience

Methane hydrate is an ice-like substance consisting of methane and water, that is stable at low temperature and under high pressure. In water depths greater than 300m (Sloan, 1990; Kvenvolden, 2000), this hydrate will form in pore spaces below the sea floor where methane is available, whether it is produced from biogenic or thermogenic sources. Yet in shallow sediments there is only a narrow stability zone (commonly a few hundred metres) for these hydrates, as temperature increases steadily with depth to a point where methane hydrate ice can no longer crystallise. The temperature of the phase transition sets a point below seabed that is marked by a change in acoustic properties – a significant decrease in acoustic impedance, where pore space is filled with free methane gas and water rather than dense ice. As temperature gradients in the first few hundred metres are consistent and reflect the heat flow in the basin, the acoustic change is found at a similar point below the seabed over large areas, generating a seismic reflector that simulates the seabed – hence a 'Bottom Simulating Reflector' or BSR.

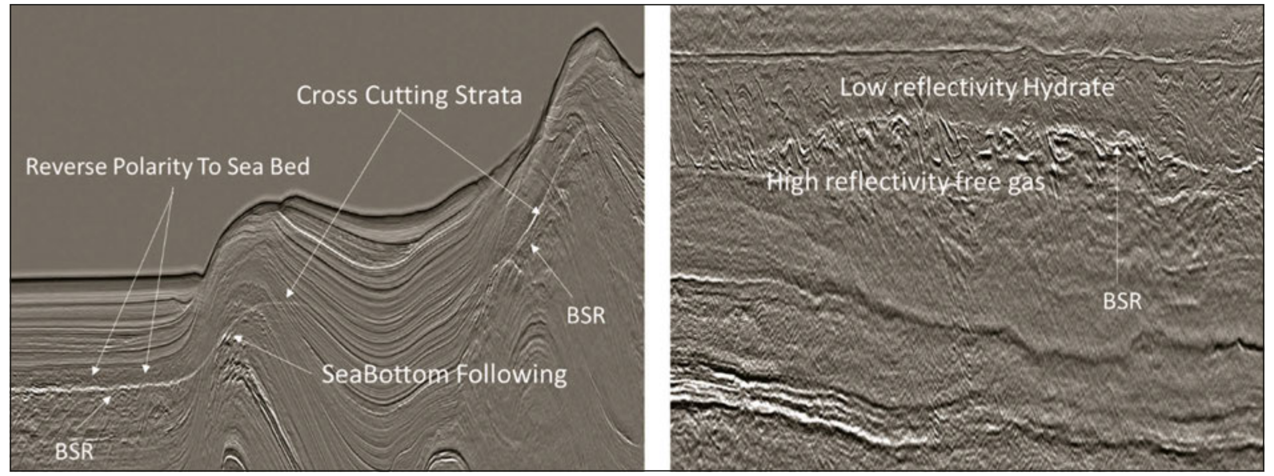
After consideration of some of the complexities of deriving the hydrate stability curve (salinity, hydrocarbon mix) and other variables (seabed temperature, BSR appearance) the thickness of the methane hydrate layer measured on seismic data can be used to estimate shallow geothermal gradients (Vohat et al., 2003). These gradients can be extrapolated qualitatively (for example Calves et al., 2010), or, with care, quantitatively (Minshull 2011), into the deeper stratigraphy to tackle one of the big unknowns in exploring for hydrocarbons in new basins – definition and constraint on source rock temperature and therefore maturity.

Identification on Seismic Data

The significant decrease in acoustic impedance observed on seismic data at the BSR generates a high amplitude event that has opposite polarity to the seabed and may cross-cut stratigraphy (see Figure 1). In general, a primary characteristic of a BSR is that it should follow and be parallel to the seabed (but read on for some colour on this…). Yet BSRs have several other distinguishing features – the hydrate may act as a regional seal trapping free gas below it in shallow reservoirs which have high reflectivity, and distinctive AVO character. Additionally, the seismic response within the hydrate appears muted, such that the amplitude of reflector response may change dramatically at the BSR (Figure 1).

It is not all plain sailing though, if the BSR is parallel to bedding it can be difficult to see, or to distinguish from stratigraphy. Also, whilst sands seem well disposed to revealing the BSR, there is often a variability of BSR response within muds and silts that is not well understood. A BSR may be visible along a line, then disappear and reappear without obvious cause. Lastly there are situations where BSRs and multiples may get confused, and where modern multiple removal techniques have 'zapped' the BSR reflector. Fortunately, in deepwater settings these occurrences are few and far between.

Figure 1: Seismic sections from the Gulf of Papua showing typical BSR characters. Left-hand section – Aure Fold belt showing BSR cutting across deformed thrusted strata. Right-hand section showing a BSR cutting through the imbricated thrusts of a mass transport system. The BSR is visible by the contrast between high reflectivity and muted reflectivity (Searcher Reprocessed PSDM).



Controls on BSR Gradients

The main controls on BSR thickness are geothermal gradient, temperature at seabed, depth (i.e., pressure), and to a much lesser but still important degree, salinity (reducing the temperature at which the hydrate breaks down) and hydrocarbon mix (increase in ethane mixed with methane will increase the temperature at which the hydrate breaks down).

A very approximate rule where little other constraint is available that may be used is that:

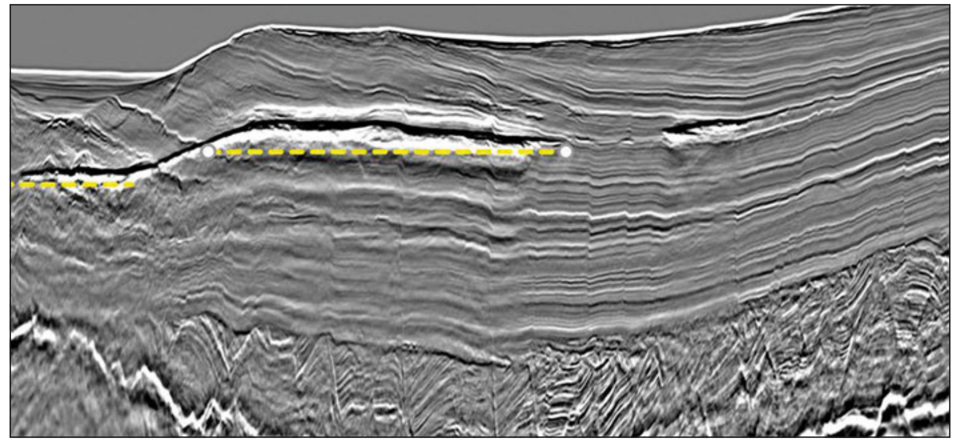


Figure 2: Seismic pseudo-depth section showing several potential hydrocarbon accumulations at the base of the methane hydrate zone. Flat base of free gas shown by yellow lines. BSR seismic example from offshore Peru (Searcher 2019 Reprocessed PSTM).

$$\text{Geothermal Gradient (from Seabed to BSR)} = (8.54^{*}\text{Ln(depth to BSR)} + 7.52)/(\text{BSR thickness}) \quad (1)$$

Note: Other rules of thumb are available. This equation assumes a seawater-methane mix, with a seabed temperature of 4°C. (Thickness in (1) is in km).

The effect of increased pressure is to increase the hydrate stability and so increase the hydrate thickness. So, looking at regional dip lines of the world's continental slopes one can see that the hydrate layer gets thicker with increased depth and therefore the BSR does not simulate the seabed. A beautiful example is shown in an article on the Pelotas Basin in *GEO ExPro* Vol. 10, No. 4 in 2013. Between shelf and basin floor, the hydrate thickens as expected due to pressure – implying that geothermal gradient does not change even though the crustal type changes from extended continental crust to oceanic crust.

Globally the thickness of a hydrate layer at a given depth in various basins is seen to vary significantly (Kvenvolden and Claypool, 1988; also see Calves et al., 2010, Figure 12). This reflects the variation in both heat flow, and in how heat flows, from basin to basin. This is key to prediction of source maturity in frontier basins, and sometimes BSRs can surprise us.

For example, BSRs are observed in the Trujillo, Salaverry, Lima and Pisco Basins on Searcher's reprocessed seismic dataset covering all the offshore basins (also see Auguy et al., 2017). However, a geothermal BSR-derived gradient based on the thickness of the hydrate layer indicates high temperature gradients of nearly 50°C/km. This has been corroborated by a value of 47°C/km observed in an Ocean Drilling Program (ODP) well (ODP 188), where methane hydrate was also recovered. Whatever the reason for these high gradients, the implications of a high geothermal gradient are very positive for future exploration as the Upper Cretaceous, Redondo Formation (Sternbach et al.,) is buried under a relatively thin sedimentary cover – like the prolific Sergipe Basin in Brazil, placing this source rock within the oil generative window. The example shown in Figure 2 shows the effect of free gas below the BSR. A pseudo-depth seismic section reveals that there are multiple separate anomalies within 4-way dip closures.

When a BSR Isn't BS: The Gulf of Papua

We have already seen that BSRs do not simulate seabed if water depths increase significantly. When the seabed is flat and a BSR does not simulate the sea bottom, however, it implies that subsurface temperatures are varying significantly laterally. In the northern part of the Gulf of Papua, in the Moresby Trough south of the Fly River Delta and west of the Aure Fold belt, BSR-derived geothermal gradients over most of the extended continental crust forming this foredeep are remarkably consistent at 32–25°C/km.

On the fold out line which runs NE–SW from the Fly River Delta through the Eastern Field Reef area in the Gulf of Papua, the hydrate layer dramatically increases in thickness approaching the reef indicating the reef is a local heat sink for the basin. The BSRs indicated on this line, either side of the carbonate reef, are the black swans of hydrate behaviour, being BSRs that do not bottom simulate.

The high thermal conductivity of carbonate relative to clastics has led to heat being wicked out of the basin by pinnacle carbonate reefs that reach the seabed. This spectacular BSR has been mapped on 2D and 3D data and indicates that the geothermal gradient decreases from 35–30°C/km from the Aure Fold Belt and the Pandora area down to 15°C/km around the carbonate reefs.

Challenging Perceived Wisdom

BSRs can be found in many frontier basins and without well data, comprise the only data-based guide for estimates on geothermal gradients. This may be qualitative or quantitative due to the uncertainties in the constraining conditions, yet they can provide a challenge to received wisdom that new venture explorers relish.

That hydrate layers at a given water depth may have variable thickness locally within a basin, suggests they may be even more useful in mapping variations in heat flow and geothermal gradient than we might have expected.

References available online. ■

The Staffordshire Basin, a system local to the Nooks Farm gas field, is thought to source many discoveries as far back as 1929, where 750 bbl were reportedly encountered from a borehole in Kingsbury Colliery, Tamworth Basin. West Midland sediments are thin and associated with risky stratigraphic traps. The Needwood Basin is an under-explored system, which neighbours the productive Widmerpool Gulf to the east. Geochemical studies by Clyde Petroleum and Phillips (1987) revealed mature source rocks underlying delta sands. Traps may exist as stratigraphic pinch-outs and tilted-fault-blocks, but prospects cannot be defined until further exploration is conducted with modern techniques and improved seismic coverage.

In the East Midlands, there is an array of proven Palaeozoic systems within a family of sub-basins. With a bias towards siliclastics, many of the traditional tilted-fault-blocks and Variscan anticlines have been heavily exploited. For this reason, future exploration is reliant on innovation. Relatively recent exploration by Low New Biggin Oil UK in 2005 noted prospectivity within lower-Carboniferous carbonates. Palaeo-karsts and dissolution pipes, capped by impermeable volcanic tuff, may contain hydrocarbons on the northern margin of Widmerpool Gulf. Similarly, Raithlin Energy (2008) investigated Permian patch reefs along the Humber Platform (Market Weighton High). Therefore, it may be worth focusing future exploration on frequently overlooked carbonates.

Timing of source maturation for much of the Palaeozoic is problematic due to the removal of overburden due to the Alpine Orogeny, 66 Ma ago. Detailed work has been undertaken to establish timing of trap preservation versus source maturation, and there is a consensus that trap development pre-dates reservoir charge during a period of maximum burial in the Mesozoic. However, a critical moment in north-east England has been difficult to establish due to the removal of post-Carboniferous rock. ROC Oil Company and Edgon Resources explored the prospectivity of north-east England in the early 2,000s but many licences have since been relinquished. Peak oil expulsion is thought to have occurred before trap preservation; in addition, other risks include intense tectonism, reservoir breach, and over-maturation from localised intrusions and basin-bounding volcanics (as noted by Enterprise as early as 1986).

Knowing this, it becomes increasingly important to apply a geological understanding to any decision-making process in the subsurface workflow; especially as exploration continues to find new and more complex traps to discover, from carbonate systems in the English Midlands to heavily folded configurations in the Midland Valley of Scotland.

Securing our Sustainable Future

To meet growing consumer demand, the UK is currently highly dependent on imported fossil fuels. With renewed exploration for onshore oil and gas, the reliance on imports could be reduced. Furthermore, with an increased supply of domestic reserves, the UK national grid may become self-sufficient and the welcomed transition to renewable energy will be economically secure. The UK onshore Palaeozoic may provide an opportunity to cover this demand. A stable, supply of domestic energy will strengthen our stance to transition towards a greener, sustainable future.

References available online. ■

Microbial Magic

How medical DNA fingerprinting can de-risk hydrocarbon exploration and production.

MART ZIJP, Biodentify;
THEO MALLINSON, Aramco Americas

Geomicrobial exploration is a novel technique within geochemical exploration. It uses the same base principle of detecting a signal at the surface resulting from vertically moving micro-seepage originating from a subsurface hydrocarbon accumulation. The technology to measure this signal is built on innovations developed over the last decade: firstly, automated DNA fingerprinting and secondly, machine learning algorithms that benefit from the exponential growth of computing power. With these machine learning algorithms, it is possible to unravel tiny differences within terabytes of sequence/microbial abundance data for samples taken above potential hydrocarbon accumulations. This makes it possible to de-risk exploration considerably and lays the foundation for a reliable, non-intrusive, and sustainable technology. The methodology is a cross-innovation from an application in medical sciences where the DNA fingerprint of a cheek swab is an indicator for the presence of specific cancers.

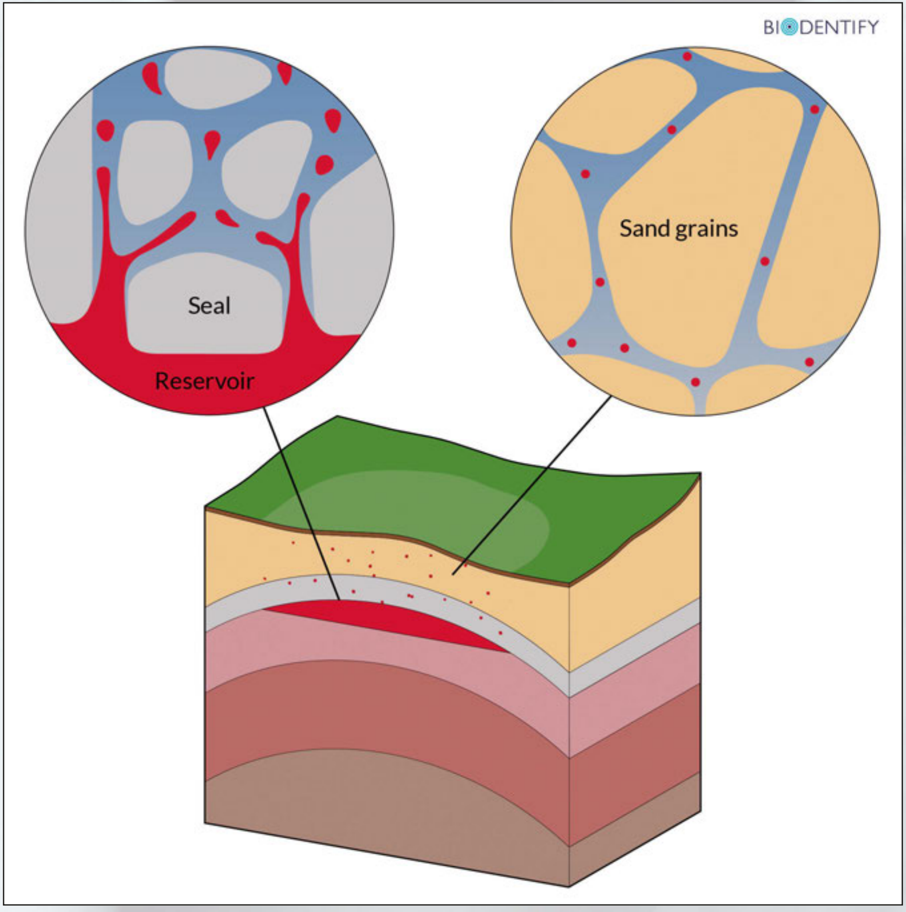
Innovative Techniques for Detecting Micro-seepage

The causal relationship between anomalies and DNA fingerprints above oil and gas fields is micro-seepage. It consists of small (colloidal size) gas bubbles that move upwards solely due to buoyancy with a speed that is > 100m/year at micro-scale. The bubbles are generated in the transition zone of gas to water, when the buoyancy pressure exerted by the gas is greater than the capillary forces in the water, allowing the gas to migrate into the water. Due to the density and viscosity differences, viscous intrusion of petroleum gas into water will appear. As the hydrostatic pressure is very high, the tips of the intruding gas 'fingers' will snap-off and form bubbles. Since the drag force that opposes the upward movement of the bubbles is proportional to the radius of the bubbles, while the buoyancy force depends on the cubic radius, colloidal-size bubbles are created. These can come together later to form clusters. This process takes place at the reservoir/seal interface, and in the upper part of a productive shale (Figure 1).

Once the bubbles are formed, they move upwards to the surface due to buoyancy (the pressure exerted by the water molecules on a bubble force it upwards). Because this process takes place from nano- to micro-scale, the micro-seepage is negligible in volume compared to 'normal' migration of hydrocarbons according to pressure differences and geology ('Darcy flow' or secondary migration).

Because of the small volume, micro-seepage is difficult to measure. However, the slight increase in hydrocarbon concentration will influence the ecology of a tiny fraction of the bacteria that live in the subsurface. Some of these metabolise the gas as a carbon source for their growth (e.g., methanotrophs/methanophiles), while others find the new environment detrimental to their growth (methanophobes or methanotoxic). The DNA fingerprinting methodology uses the 16S rRNA gene as a unique genetic indicator for a specific bacterial species. A schematic representation of the steps for DNA fingerprinting is shown in Figure 2. The most difficult and determining step for the quality is the extraction of

Figure 1: The origin of micro-seepage is the displacement of water with colloids of gas in the lower part of the seal.



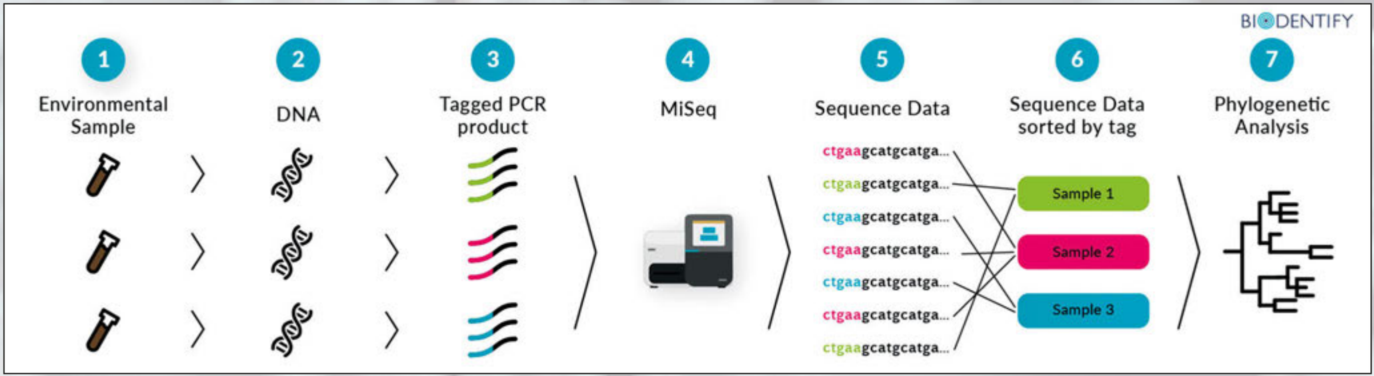


Figure 2: Schematic steps in microbial fingerprinting: identification of which microbes are present in the soil samples and their abundance.

DNA from the soil. Our methods for this have been optimised during the processing of nearly 10,000 samples that are currently available in our database.

The second innovation used is machine learning to find the ~100 microbial species that indicate oil and gas presence out of the millions of species present in the DNA fingerprint of the soil sample. The power of machine learning lies in the possibility to effectively check all possible combinations to pinpoint the required 100 species (by a 'deep learning neural network') and in maximising and extensively testing the predictive capability of candidate models. Training and calibration are followed by validation, which is checking that the predictive accuracy on reserved data samples is correct, as shown in Figure 3. Only when the prediction accuracy is acceptable is the model used to predict new/blind samples, otherwise the predictive capability of the model is improved first.

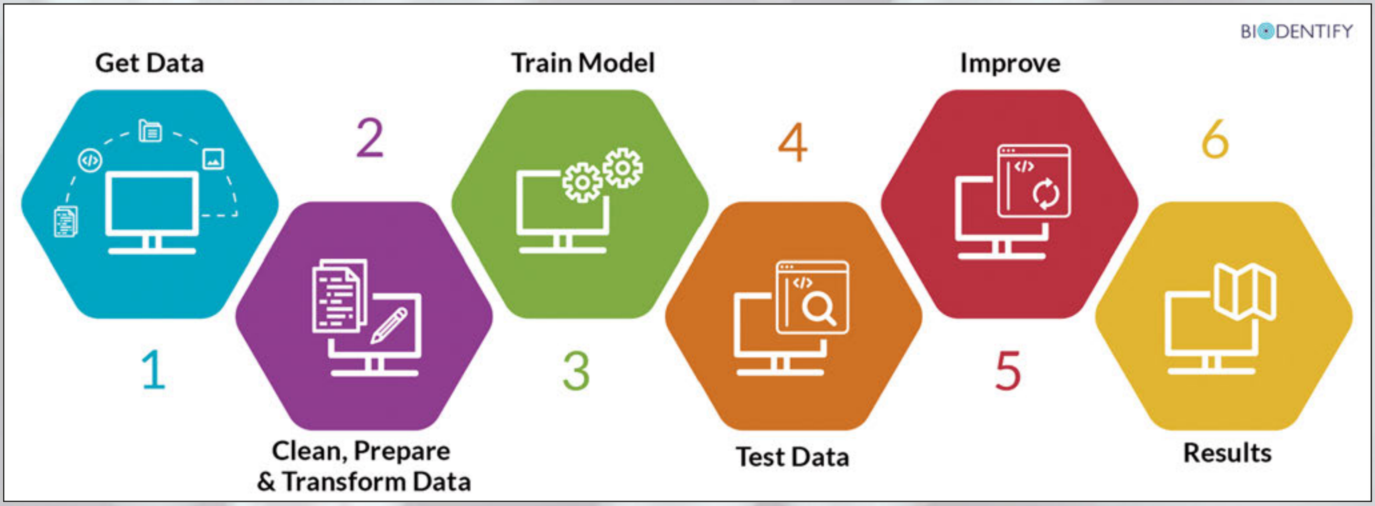
In the Field, an American Case Study

In recent years, several successful proof-of-concept projects have been carried out which have been published in articles and at conferences and exhibitions. One of these projects was an extensive proof-of-concept pilot carried out in the Bakken and Eagle Ford Shale Formations in the United States. To obtain an accurate prediction of the customer-supplied blinded samples, we used the following workflow (Figure 4), also described in more detail by Te Stroet et al. (2017). Firstly, soil sampling was conducted 1 ft below the surface (half a teaspoon). Next, DNA analysis was undertaken resulting in DNA fingerprints of the microbial ecosystem of each sample. Then modelling and validating of the microbes that determine the hydrocarbon presence was undertaken and finally, mapping and predicting the prospectivity of new samples.

The goal of this project was to investigate whether the technique can distinguish between high and low producers in the Bakken (North Dakota) and Eagle Ford Shale Formations (Texas). In order to do this, 540 samples (Figure 5) were taken above selected high and low-producing wells, subdivided into three different sets: high and low-producing wells in the Bakken oil shale, high and low-producing oil wells of the Eagle Ford, and high and low gas producers of the Eagle Ford. To obtain valid predictions, 200 samples (70 from the Bakken, 30 from the Eagle Ford oil window and 100 from the Eagle Ford gas window) were blinded by the customer after sampling. From 340 non-blinded samples the abundances of all microbes present per sample were analysed using machine learning. The algorithms look for differences above known highly productive wells and wells with known low productivity and then uses these to train a predictive model.

This was done by three modelling loops: 1) an inner loop of non-blinded

Figure 3: Extensive testing of predictive capabilities with machine learning.



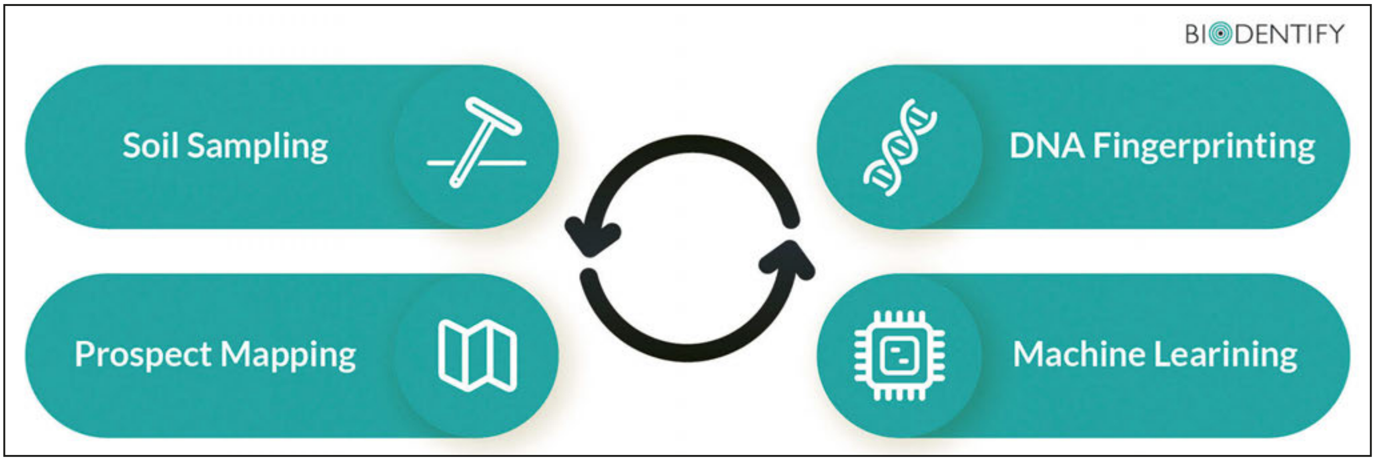


Figure 4: The workflow used to obtain an accurate prediction of samples which were either blinded by a customer beforehand, or when the subsurface potential charge is unknown.

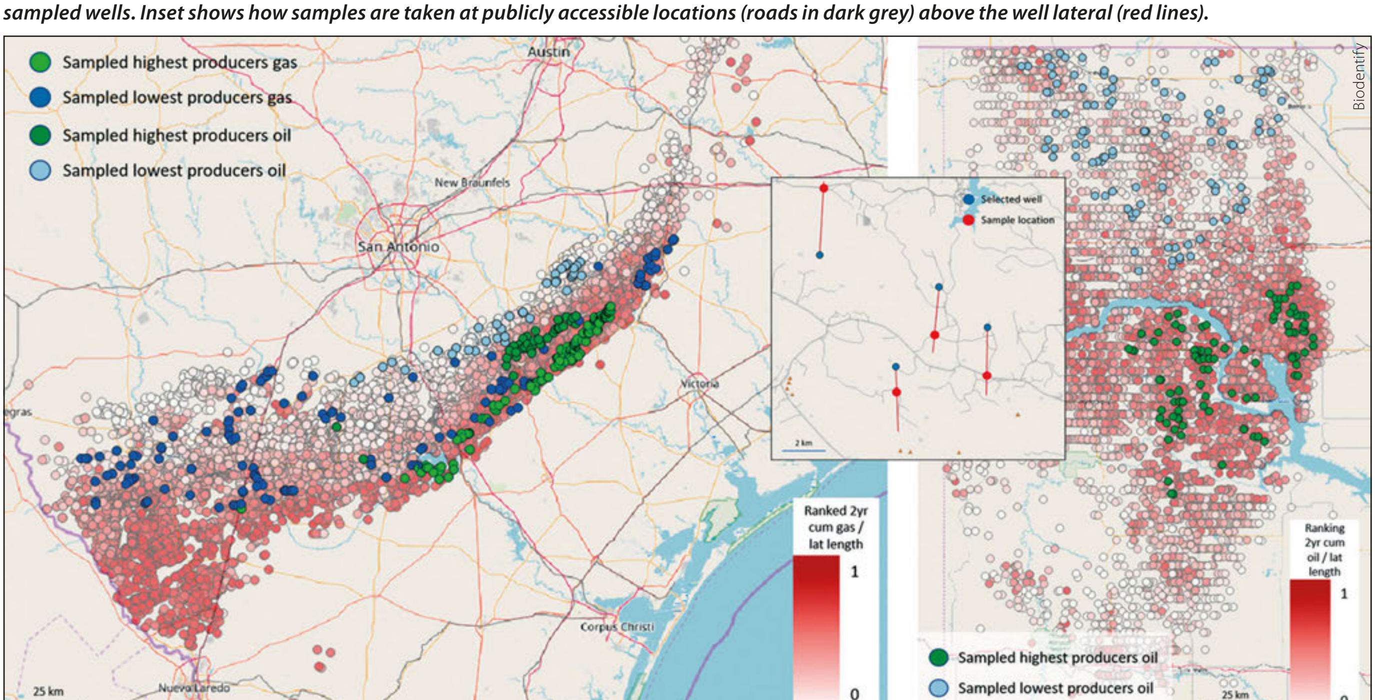
samples used to correlate DNA fingerprints with known well productivity, also known as the training set; 2) an iterative second loop of non-blinded samples not used for training that are predicted and cross-validated with known well productivity, referred to as the validation set; 3) an outer loop which predicts the productivity of the blinded samples by using the parameters of the second loop. To preserve data integrity, the client applied a randomisation mask to the blinded samples and evaluated the delivered prediction results by removing the randomisation mask. The resulting model achieved an accurate prediction of well productivity of 85% on the blinded samples.

Following this it was necessary to evaluate whether a model trained in one location could be used to predict a different location. To test this 'exportability', we used the combined data from the Bakken and Eagle Ford Formations to predict the productivity of one of the other study areas, the Vaca Muerta Basin in Argentina. The result was that the USA dataset (540 samples) predicted the Argentina blinded samples with an accuracy of 83%, despite the study areas being several thousand kilometres apart and in different climatic zones. This means that the selected bacteria are found in both locations, and analysis of their reaction to the presence or absence of microseepage can achieve consistently good results.

Decrease Environmental Impact, Increase Drilling Success

From this exercise we conclude that the large number of shale wells and the public reporting of production information in the USA, make it very suitable to use DNA fingerprints of shallow soil samples to develop a robust machine learning model which predicts hydrocarbon production with an accuracy of around 85%. The potential for application of a trained machine learning model on geographically distant areas is demonstrated. Whilst having local samples and

Figure 5: Sample locations of the Eagle Ford Shale (left) and the Bakken Shale (right). Red/white dots show all drilled wells per play, blue/green dots are sampled wells. Inset shows how samples are taken at publicly accessible locations (roads in dark grey) above the well lateral (red lines).



productivity data increases the accuracy of study results, the USA data-trained model provided predictive accuracies above the success threshold when considering Argentina samples. This indicates that in addition to providing a development criterion complementary to other available techniques for existing fields, new fields in non-contiguous areas can also use this innovative and non-intrusive approach for prospect evaluation, de-risking, and initial well selection prior to production data being available. In currently ongoing offshore work, quite different bacterial ecosystems have been found to be present, compared to onshore, and the next phase is to diligently develop and build a corresponding sample database to support further efforts in this area.

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Geothermal Energy

A new frontier for energy – and petroleum geoscientists.

DR ELLIE MACINNES, CGG

Last year certainly brought us all unexpected challenges and perhaps some new opportunities. In my own career, the opportunity was a new role as Head of Geothermal Science at CGG. This personal career move was driven by the renewed global focus on the potential for geothermal energy to play a greater role in the Energy Transition.

When I joined ConocoPhillips in 2004, after completing a structural geology PhD at the University of New Brunswick in eastern Canada, I was fortunate to join the oil and gas industry at a time of relatively high oil prices and significant investment in new graduates. Since then, I have weathered the ups and downs of the industry at Talisman Energy in Calgary, followed by Maersk Oil in Copenhagen, while building my expertise in Exploration and New Ventures in basins around the globe. My latest career move was in 2018 when I joined CGG in the UK. This was after a difficult period of market down-cycle, and I was excited to be able to stay in the energy industry. The recent acceleration of the Energy Transition is in stark contrast to the difficult circumstances faced by our oil and gas community.

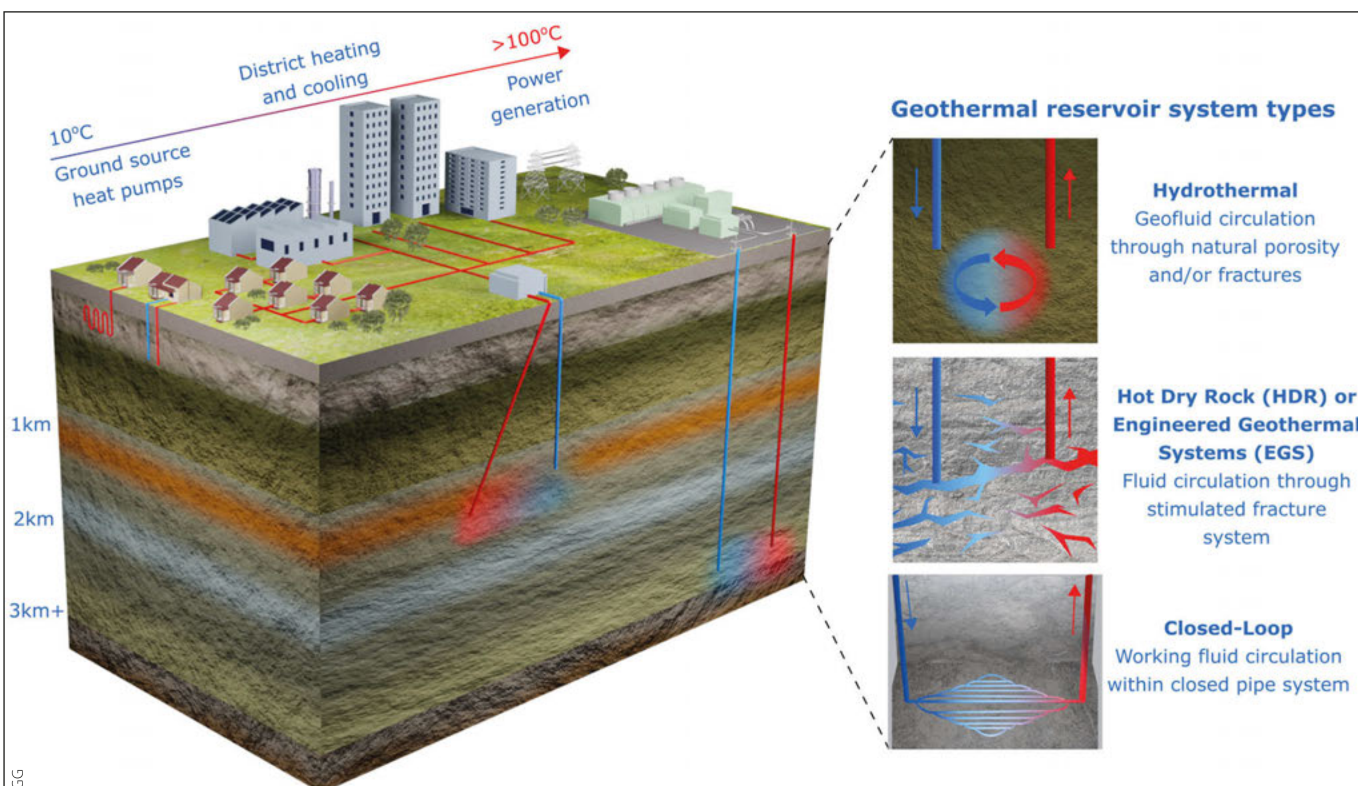
Transferable Skills

As traditional oil and gas companies look for clean energy investment opportunities, there is a high level of interest from subsurface technical specialists who are keen to learn and demonstrate how their knowledge and skills can be applied in this growth area. I have observed excitement and some trepidation within all experience levels of geoscientists – excited at the new opportunities arising and the global push to meet climate change targets, yet uncertainty around where we fit as geoscientists.

With the launch of the United Nations 'Race to Zero', a global campaign to rally leadership and support from businesses, cities, regions, investors and universities for a healthy, resilient, zero carbon recovery, and the upcoming 26th UN Climate Change Conference of the Parties (COP26) in Glasgow, November 2021, there is a sharp focus on the actions needed to reach the goals of the Paris Agreement and the UN Framework Convention on Climate Change. Geothermal makes a relatively minor contribution to global renewable energy, a sector currently dominated by wind and solar. However, in the next five years the installed geothermal electrical power generating capacity is forecast to expand from 16 gigawatts (GW) at the end of 2020 to 24GW in 2025 as energy companies diversify into alternative markets (Rystad Energy 2020). Recent announcements from BP and Chevron Technology Ventures that they are investing in new geothermal technologies that include heating and cooling has highlighted the growing interest in geothermal from 'Big Oil'.

Geothermal energy is the thermal energy generated and stored within

Figure 1: Multiple geothermal energy uses and technologies dependent on the depth to reservoir, heat available and energy needs.



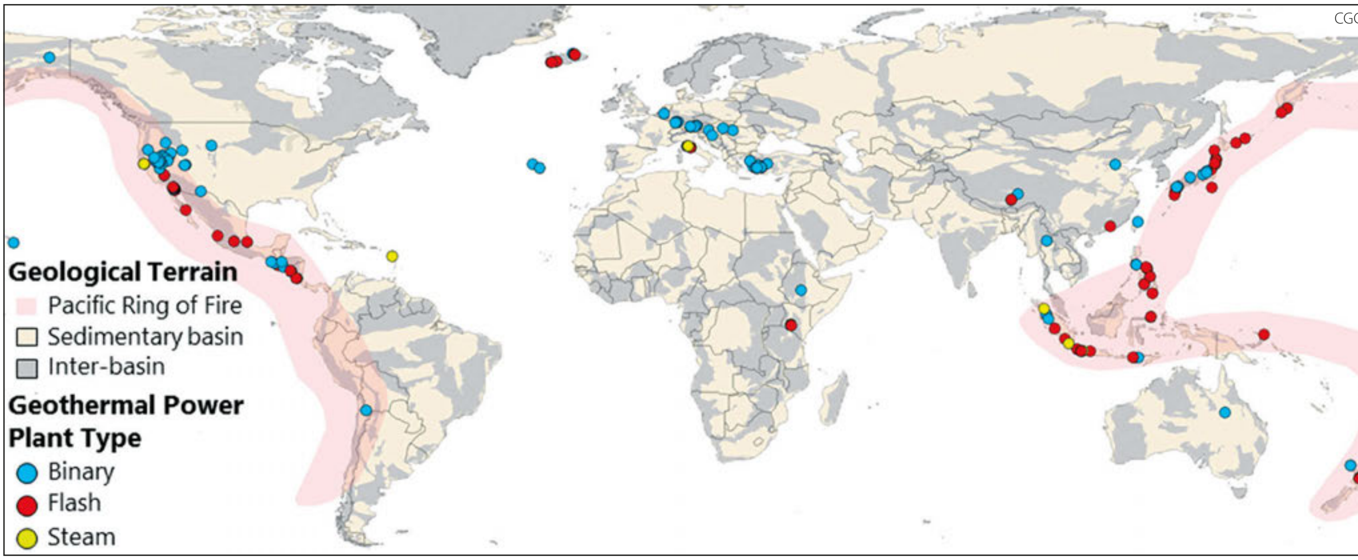


Figure 2: Location of geothermal power plants concentrated around the Ring of Fire. Sedimentary basins are identified as areas of future geothermal energy growth potential.

the Earth (from radioactive decay of minerals and the heat associated with the formation of the Earth). Humans have harnessed the surface manifestations of geothermal energy from hot springs for cooking, bathing and warmth for thousands of years. The first geothermal plant was established in Larderello, Italy in 1904. One of the great advantages of geothermal is the flexibility associated with how we utilise this energy; it can heat, cool and generate electricity (Figure 1).

Constant Energy

Geothermal energy is 'always on', meaning, unlike solar and wind, the energy produced is constant and does not depend on weather or daylight. Geothermal energy below about 120°C can be utilised directly as heating/cooling for residential and industrial purposes, for drying in manufacturing processes and in agriculture/aquaculture. All these uses can be applied without access to a power grid and are particularly beneficial in areas lacking a well-developed electrical grid or if the existing grid is at full capacity. Alternatively, geothermal temperatures above 120°C can be converted directly to electricity and supplied to the grid using flash, steam or binary turbine systems. Geothermal plants can have a relatively light geographic footprint in urban areas (approximately two football pitches) and emit a very small fraction of carbon compared to hydrocarbons or coal. While the upfront capital expenditure for a geothermal plant is typically high, the life span is 25–30 years and can be up to 50 years, with little downtime, giving a very competitive levelised cost of electricity (LCOE) compared to other renewable energy sources. With the increased investment in new technologies, the LCOE will likely fall in a similar way to solar and wind.

An exciting potential use for geothermal energy is the production of green hydrogen and ammonia. A variety of different industries (e.g., shipping, aviation, power generation and manufacturing) are collaborating with governments and universities to increase the use of ammonia and hydrogen as a viable alternative to fossil fuels. Green ammonia has a greater power density than hydrogen and can also be used for fertiliser, the decarbonising of food production being an important element in the 'race to net zero'.

Historically, geothermal energy has been developed in areas with high-temperature systems. These are characterised by volcanoes and proximity to plate boundaries, for example, around the 'Ring of Fire' (Figure 2). The countries with well established, high-temperature geothermal energy include Iceland, New Zealand, Kenya and Indonesia. It is not just high-enthalpy areas that can provide reliable geothermal energy. In recent years there has been development in fractured granitic basement rocks, such as the Upper Rhine Graben in France (Figure 3) and Espoo in Finland where a recent geothermal well reached 4,600m in depth. Sedimentary basins, areas where oil and gas geoscientists have honed their skills and technology, hold vast potential to provide geothermal energy to help us meet our challenging global climate change targets (Figure 2). And a new frontier in geothermal potentially exists in exploring the offshore, a perfect match for oil and gas technologies and expertise.

While the subsurface geoscience skills required for geothermal exploration and development differ from those required for oil and gas, there are existing skills and technologies that are highly transferable. Moreover, as the shift for geothermal resources moves away from high-enthalpy areas and towards sedimentary basins, the transfer of oil and gas industry techniques, skills and data will be beneficial to the geothermal industry by providing a fresh subsurface technical perspective and the adoption of new drilling and completion techniques.

Similar Technologies

The geothermal reservoir is a volume of rock and fluids that is at an elevated temperature. The temperature may simply be due to a combination of depth and geothermal gradient, the

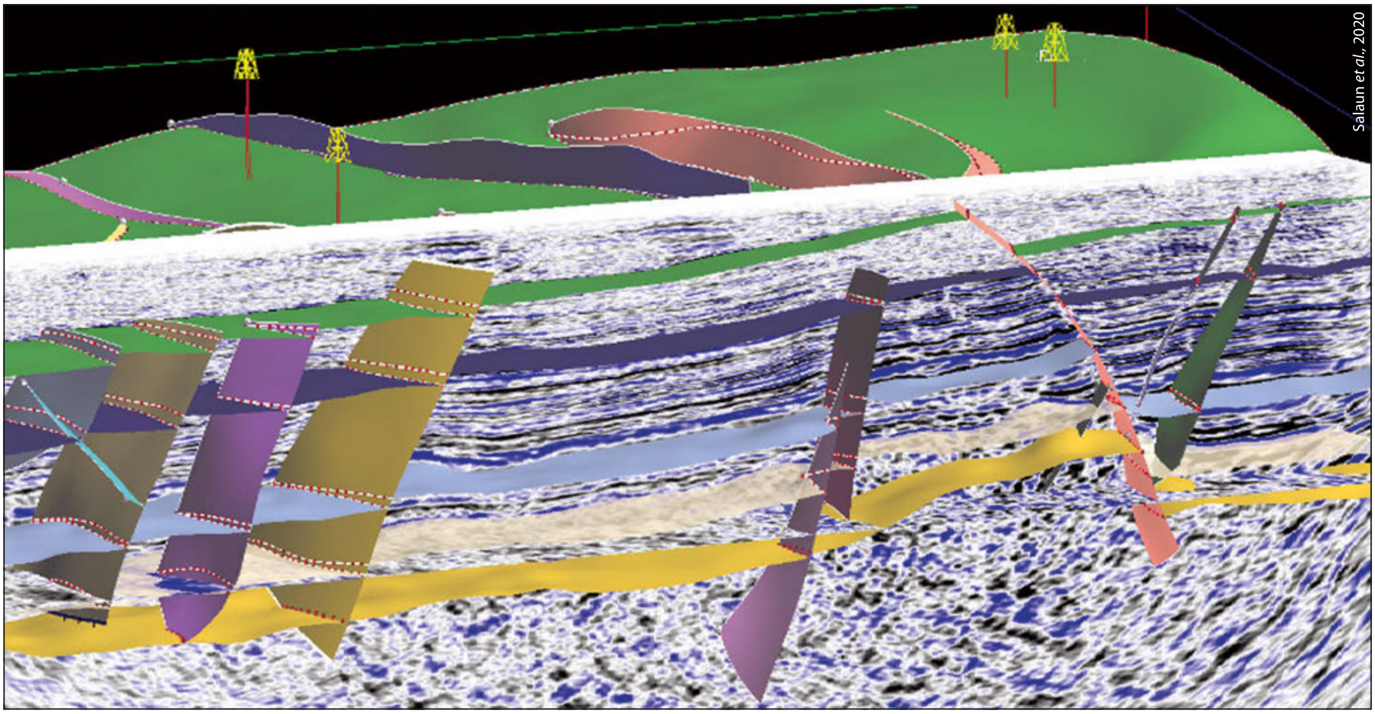


Figure 3: 3D structural model built from interpreted seismic volumes to inform well planning, Upper Rhine Graben, France.

Figure 4: Multi-physics 3D modelling delineates most prospective geothermal reservoir zones.

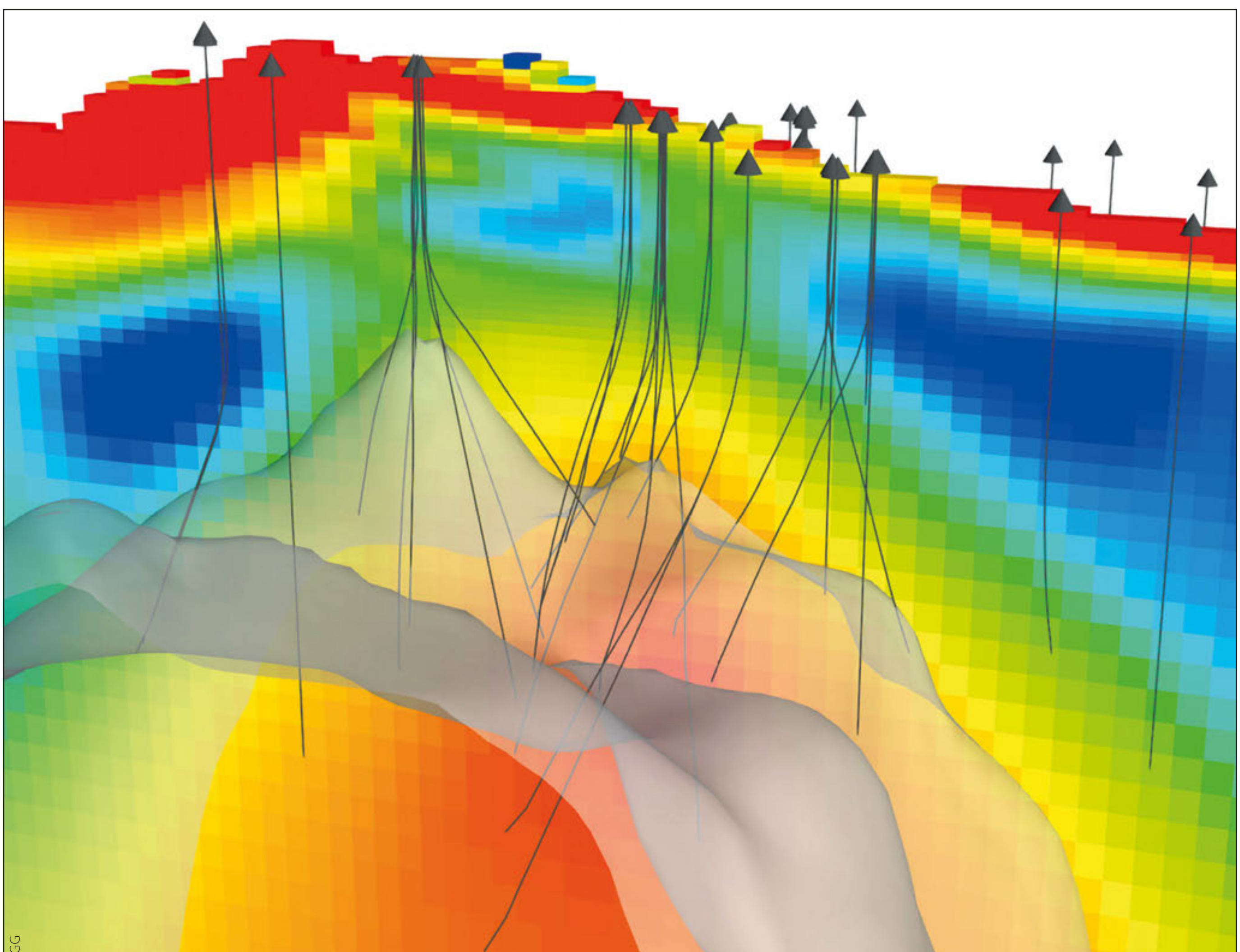


Figure 5: An example of geothermal Data Dashboards which incorporate global subsurface and above-ground data, key to geothermal resource exploration and development.

latter partly controlled by conductive heat flow, which varies with geological setting. In other cases, heat flow may be assisted by convective or advective movement of fluids, which may be expressed at the surface by geysers, fumaroles and hot springs. Like oil and gas reservoirs, there are many different geothermal play types, yet there remain some constant geological factors that must be understood. For example, characterising the permeability and porosity of a reservoir is fundamental to calculating the thermal resource. The assessment of permeability and porosity uses similar workflows and techniques common in the petroleum industry (e.g., analysis of core, cuttings, wireline logs, petrophysics, seismic and fracture analysis). A major difference is that the solid rock forms part of the thermal resource and the rate at which heat can be transferred from the hot rock into the flowing fluid forms an important part of our geothermal resource assessments (Bolton et al., 2020).

Like oil and gas exploration and development, the combination of high-resolution 3D seismic data processing, high-end imaging and enhanced interpretation (as illustrated by Figure 3) provides geoscientists and engineers with the information required to model complex fault networks, reservoir characteristics and position production wells with accuracy (Salaun et al., 2020).

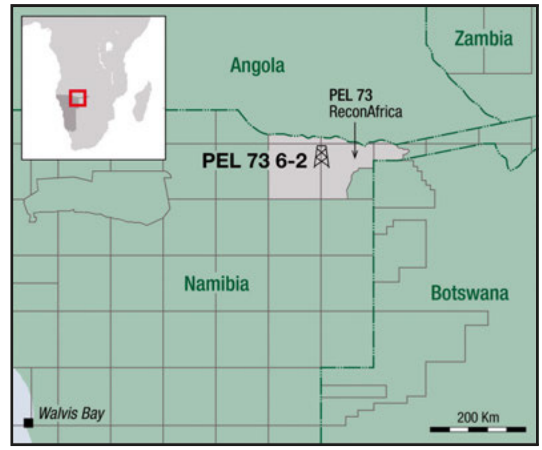
3D conceptual reservoir models of geothermal reservoirs (Figure 4) include the types of subsurface data used in typical oil and gas models (wells, seismic interpretations, facies models, production data, pressure data, structural and stratigraphic models, etc). However, geothermal reservoir models also utilise a variety of multi-physics data which includes gravity, magnetics, magnetotellurics (MT) and micro-earthquake (Soyer et al., 2018).

An exciting part of evaluating the potential for geothermal developments in sedimentary and offshore environments is the incorporation and analysis of vast oil and gas subsurface datasets with geothermal datasets (Figure 5). This combined role of the data scientist and geoscientist in repurposing vast quantities of data, originally collected to explore for and develop hydrocarbon reservoirs, offers valuable new ways of exploring for geothermal (Hardman et al., 2020). Other geoscience skills and technologies used in both sectors of the energy industry include satellite mapping, reservoir engineering, seismic interpretation and processing.

As the geothermal industry continues to adopt new drilling and extraction technologies (such as multilateral closed loop systems, enhanced geothermal systems and potentially, offshore wells), the need for the transfer of technologies and subsurface expertise between the oil and gas sector and geothermal sector will open up new avenues for subsurface specialists looking to expand their skill sets and explore new opportunities.

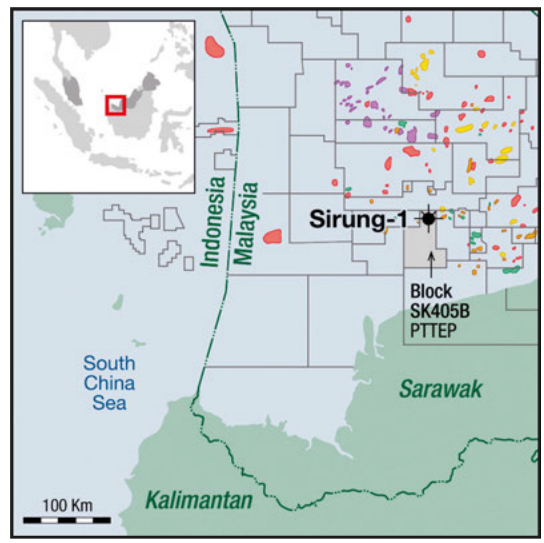
Further references available online. ■

Establishing a Working Petroleum System in the Kavango Frontier



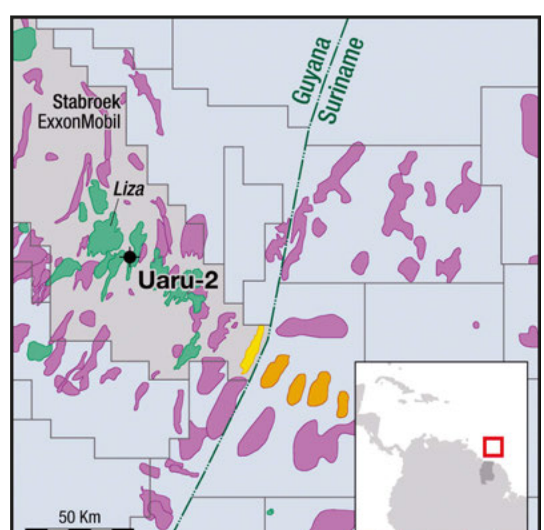
ReconAfrica, the Canadian listed firm, has seen its market value surpass C$1bn recently, with initial results from its first stratigraphic well onshore the **Kavango Basin** in **Licence PEL 73** in north-east Namibia. The 6-2 well, first of three, targeted **Karoo Group** and equivalent formations in the **Prince Albert, Whitehill and Collingham Groups**, and the **Lower Ecca Group**. High resolution aeromagnetic data over the licence is interpreted as showing a deep basin with optimal conditions for preserving a thick interval of organic-rich marine shales. With drilling, coring and logging operations now complete on this first well, clear evidence of a working conventional petroleum system has been shown with intervals penetrating highly porous, permeable sediments and marine source rocks, and an extensive marine carbonate lithofacies. Mud gas results indicate a high BTU gas with the presence of light oil in numerous cutting samples. Overall, the operator reported over 200m of oil shows within three intervals. The rig is now being mobilised to the 6-1 location, 16 km north of 6-2 drill site. ■

Extending the Highly Productive Gas Play in Sarawak



PTTEP are continuing a winning streak on their acreage offshore **Sarawak**. The Thai company announced its offshore **Sirung-1** exploration well as an oil and gas discovery, intersecting a column of more than 100m in Miocene clastic reservoirs. The well is in **Block SK405B** and is located in the shallow waters, approximately 137 km off the coast of Sarawak (Bintulu). **PTTEP Sarawak Oil Limited** is the operator with 59.5% participating interest. **Moeco Oil** and **Petronas Carigali** are partners. The Sirung-1 discovery is PTTEP's third discovery offshore in the Sarawak Basin this year, following **Lang Lebah-2** in **SK410B** and **SK417's Dokong-1**. PTTEP plans to drill a Sirung appraisal well this year, along with several other prospects in this Sarawak acreage. ■

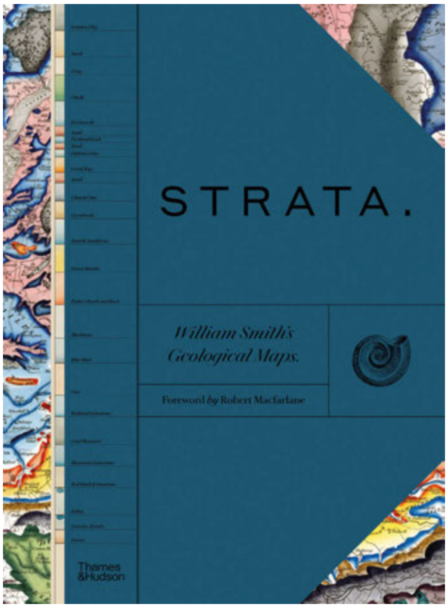
Pushing the Envelope Offshore Guyana



ExxonMobil and partners **Hess** and **CNOOC** have made another oil discovery offshore **Guyana** with the wildcat well **Uaru-2** on the prolific **Stabroek Block**. The well encountered 36.7m of oil in Cretaceous sandstones, with some oil pay in deeper formations than the **Uaru-1** well. This adds to the previous recoverable resource estimate of approximately 9 Bboe. Ultra-deep water drillship Noble Don Taylor drilled the exploration well Uaru-2 and will move to spud the exploration well **Mako-2** after completion. ExxonMobil currently has six drillships operating in the region. This recent result supports the target of eight floating production storage and offloading (FPSO) developments on **Stabroek**, comparable only to the giant pre-salt developments in the Brazilian Santos Basin. The final tally could reach 10 FPSOs, hinting at an overall gross production rate of 2 MMbopd, surpassing the traditional oil-producing heartlands of West Africa and the North Sea. ■

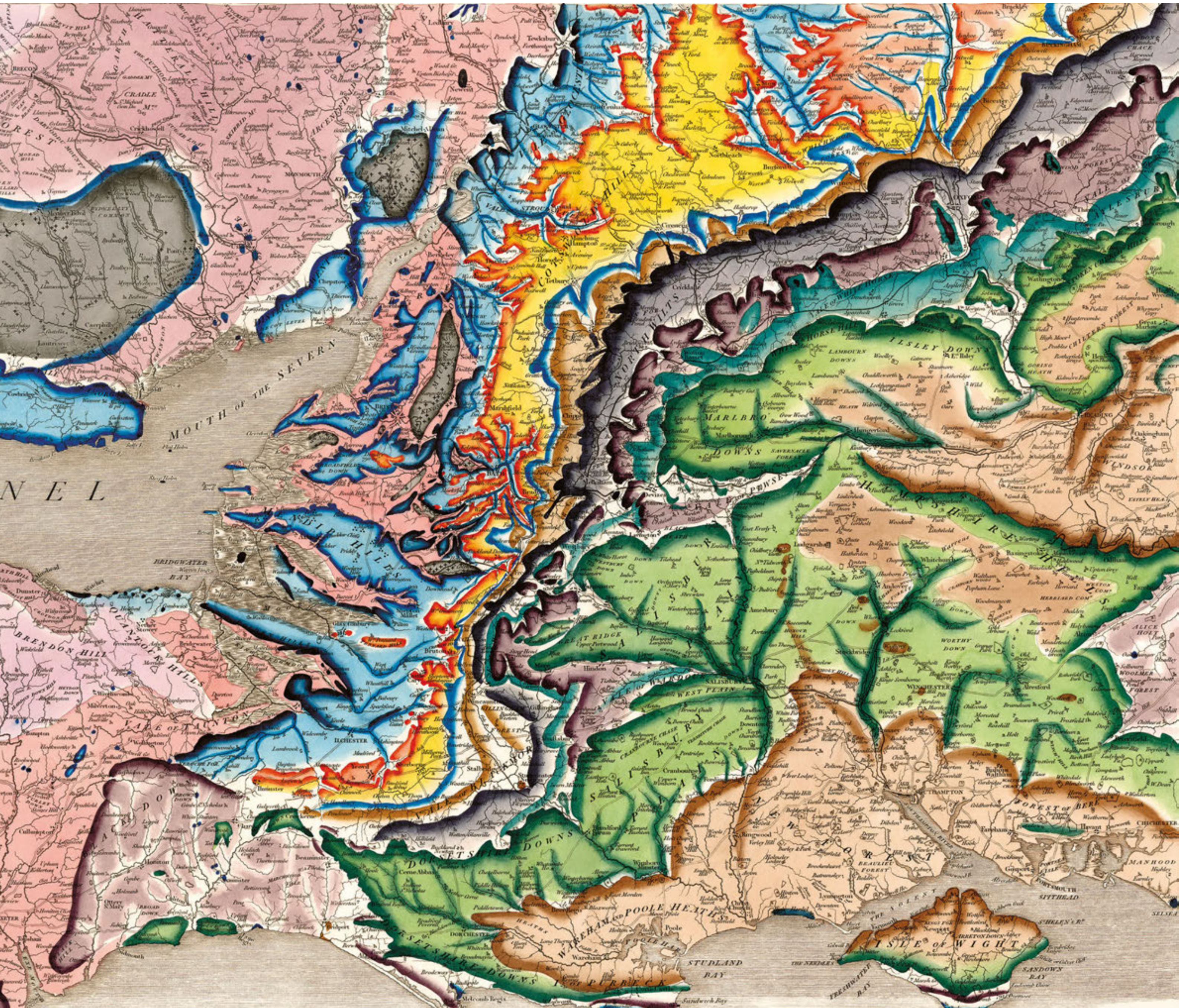
STRATA – William Smith's Geological Maps

IAIN BROWN



Created in collaboration with Oxford University Museum of Natural History and showcasing the best of William Smith's archive, STRATA traces the life and work of William Smith from apprentice surveyor to scientific icon.

Most British geologists should be aware of the importance and significance of William Smith (1769–1839). The son of an Oxfordshire village blacksmith, with little in the way of formal education, he singlehandedly went on to produce in 1815, the first, largely complete geological map of England, Wales, and 'part' of Scotland. Much more than a map, it was a comprehensive account of the stratigraphy, associated fossils and uses of each of the principal rock types of Britain.



A Beautifully Curated Volume

What most of us who have been lucky enough to have had a career in geology have not easily been able to do until now, is to see these maps collected together in an easy to access, albeit weighty, single volume. Partly a showcase of Smith's remarkable body of work and partly a sumptuous 'coffee table' art book, it is a lovingly and beautifully curated volume. The reader will find it filled with all of Smith's individual sheets which made up the 1815 map and a host of beautifully reproduced plates of fossils, cross-sections, engravings, as well as the individual geological county maps he created later in his career.

A Comprehensive Showcase of a Lifetime's Work

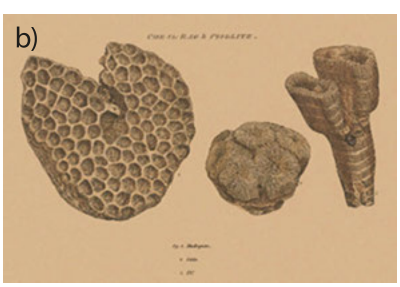
The introduction to the book sets Smith's work within the context of the geological theories and ideas of the time and then the volume is organised into four geographical sections, each represented by four sheets from the famous 1815 map. In each section the maps are beautifully accompanied by cross-sections and the appropriate county maps, as well as James Sowerby's detailed fossil illustrations.

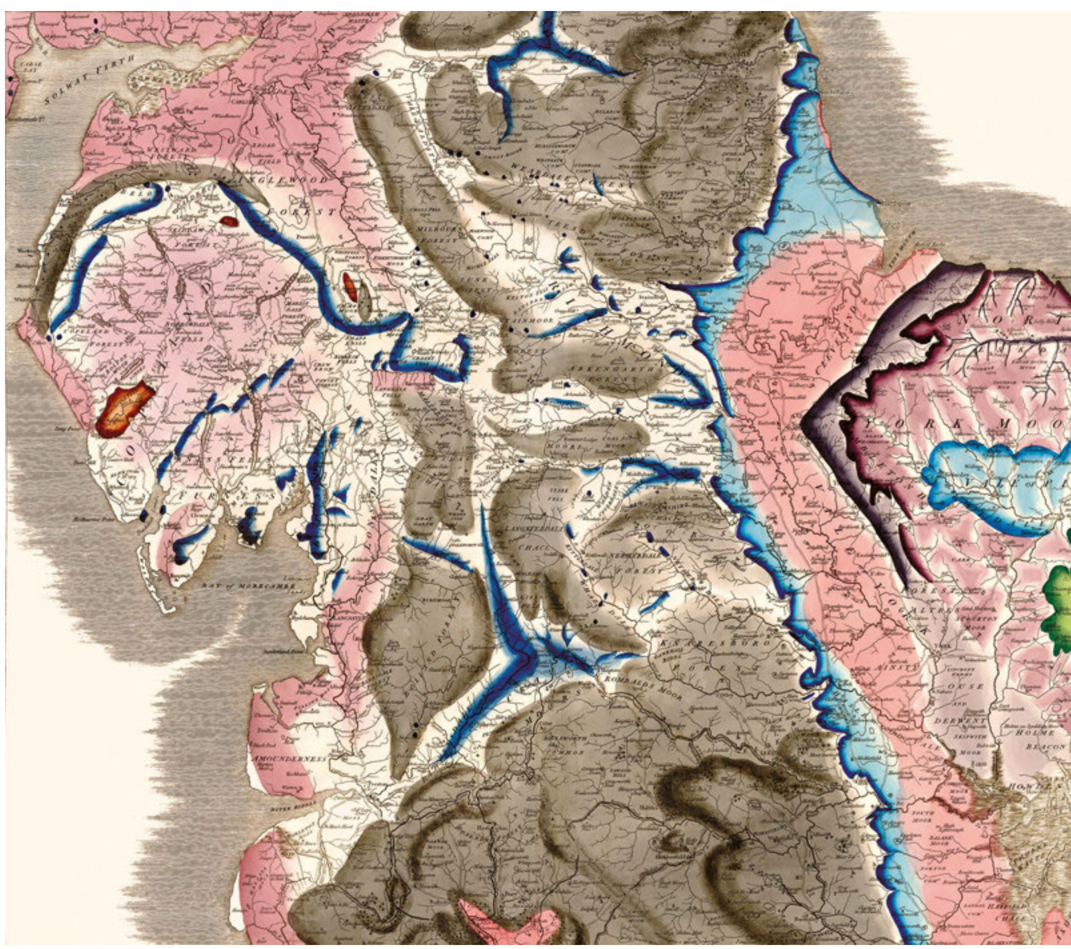
Between the various sections are accounts by prominent academics and experts, exploring the objectives and significance of Smith's work and its impact and use in the fields of palaeontology, mining, stratigraphy, cartography and hydrology. Later in the book we learn about the rivalry with the establishment, in particular the then President of the Geological Society, George Greenough and his competing geological map, which was published after Smith's in 1820. Smith's incredible contribution to British geology was acknowledged in 1831 by the Geological Society when he became the recipient of the first Wollaston Medal in recognition of his achievements, and the influence of his geological mapping and biostratigraphical theories on the sciences, culminating in the establishment of the modern geological timescale.

811 Stunningly Coloured Maps and Illustrations

Now to the tricky business of price. This book is not inexpensive, retailing at around £50. Is it worth this outlay? I can only say yes, every penny. This is one of the most beautifully designed and illustrated 'scientific' books I have ever seen. It is a large volume at 27 × 2.8 × 37 cm, but this seems to me the perfect size to showcase the 811 beautifully coloured maps and illustrations. You do not have to be a geoscientist to enjoy and benefit from this volume; any lover of beautiful books and maps will appreciate it.

The 'Timeline of Events in the Life of William Smith', on page 19, concludes in 1839 with William Smith's unexpected death in Northampton due to a chill caught while travelling to a scientific meeting in Birmingham. He is buried in the churchyard of St Peter's church, Northampton. As a county resident, I think I will be taking a trip there soon to pay my respects to this icon of British earth science. ■





Above: a) Fossils found in Oak Tree Clay; b) Fossils found in Coral Rag and Pisolite. (William Smith Printed by W. Arding, London 1816)

Left and right: 2 maps showing a Delineation of the Strata of England and Wales with part of Scotland. (William Smith, 1815. © University of Oxford, Museum of Natural History)

Published by Thames & Hudson, available from bookshops and online.

Unconventionals in the US: What Next?

Susan Nash, the Director of Innovation and Emerging Science/Technology at the AAPG talks about how US unconventionals are adapting to a transitioning world.

How do you think the new Biden administration's energy policies and attitude towards oil and gas will impact unconventionals in the US?

The Biden administration's stated objective #5 of the 9 Key Elements of Joe Biden's Plan for a Clean Energy Revolution is to "accelerate the deployment of clean technology throughout our economy." This is creating a massive impetus to transition to low-carbon energy, and to invest in geothermal energy and energy storage such as in carbon capture usage and storage (CCUS). For example, ExxonMobil has announced a $100 billion carbon capture and storage plan that utilises the salt domes in the Gulf of Mexico. Government support is also providing tremendous incentive to further modify operations in order to avoid emissions, waste, and pollution. Most people think of 'unconventionals' as being shale gas, but in reality, the term, 'unconventional resources', can apply to any energy that is not a high permeability, high porosity reservoir. It is also providing tremendous incentives to further modify operations to avoid emissions, waste, and pollution. Therefore, there are a number of ways in which low permeability, often laterally drilled wells, can be partnered with green energy. For example, low-volume gas can be used in conjunction with geothermal, as can solar, to utilise existing wells to store energy as well as produce it. Repurposing suitable oil and gas wells for geothermal energy may also be a growth area in the future.

US unconventionals will probably look different in the next few years – perhaps smaller and dominated by a high-graded or integrated portfolio of data-driven operators. How will new technology feed into this scenario?

In the case of data-driven operators, success hinges on new technologies: sensors, cloud-based analytics, software that enables 'smart' operations, and machine-learning powered programmrs that have the predictive power necessary to make it possible to automate maintenance and operations. Interventions in the case of leaks or emissions can be automated as well. Perhaps one of the most promising areas of incorporating new tools and technologies and solving supply-chain issues is in the area of additive manufacturing. The use of drones and satellites for monitoring and planning surface logistics is also beginning to be an integral part of operations. Surface images are provided by satellites owned by companies such as Maxar or gathered at lower altitude by drones by providers such as Juniper Engineering.

S.Nash

The future of US shale could also hinge on how successfully it can adapt itself into a greener future. Do you see any trends in this area?

I see a tremendous investment in diversification, both in avoiding greenhouse gas emissions and hazards such as induced seismicity, as well as in rethinking the depleted laterals and considering ways to use them for energy storage, or in energy optimisation. It is interesting to see how many people are doing creative work that cuts across energy silos. For example, energy minerals expertise is vital in newly implemented produced brine mining where lithium is being extracted. The concentrations are low, but the volume can be very high in certain reservoirs. Water management in general is developing in many new and important directions, and something to consider as water scarcity is an increasingly urgent issue in the world. If water processing technologies can bring costs down, today's shale industry could be tomorrow's water industry.

Unconventional development in the US has been characterised by three trends: rapidly rising production, continual investment, and persistent negative free cash flow for the independents. How do investors currently view investment in this area?

Investors are currently looking closely at gas sourcing, and closely evaluating the technologies used to produce 'blue' hydrogen from natural gas, with carbon capture and storage (CCS) technology disposing of the in-situ CO_2. Service company giant Schlumberger has teamed with Thermal Energy Partners (TEP) to create STEP Energy, a geothermal energy company, to develop efficient and profitable geothermal power generation projects. Companies such as Project Canary are focused on 'ethically sourced gas' and certify that companies are producing their gas with the proper safeguards against leaks and emissions. There are potential tax benefits and even grants that were passed as a part of the Covid relief bill(s), which provides even more incentive. The key is to turn a short-term stimulus into a long-term sustainable benefit.

With countries such as Mexico and Australia having potential shale plays, what developments do you see coming internationally in this area?

Mexico has vast potential shale plays which several geologists have been promoting for many years. There is little appetite at present for exploring and putting them in production in the near term due to the public's negative view of hydraulic fracturing and a few internal issues. Further, the initial capital investment required is significant. As soon as the climate is more positive for foreign investment, and technologies are in place to create blue hydrogen as well as clean electricity, the situation may change. There are also significant water issues to be considered, which must be addressed in the overall plan.

Australia's mining industry has great synchronicity with shale, particularly in co-production of brine minerals and the use of blue hydrogen to help process battery metals.

In general, one can say that the future will consist of complementarity and using the resources where one has the highest comparative advantage to spur local economic growth and increase meaningful economic access. ■

Making a Date with the Data

How do you process data so it's usable? This question came up at a real estate seminar recently but it can equally be applied to the oil and gas sector. Whether you're trying to monetise climate risk or find new ways to extend the life of offshore assets, getting access to usable data is a vital part of the equation.

It's also key to an industry in transition. Follow the data down the yellow brick road to more automated, more efficient and less energy intensive assets. "Digitalisation will be the backbone of the energy transition," noted John Markus Lervik, CEO and founder of the software company Cognite in a recent interview. While this could be taken as a little self-serving from a CEO with a large stake in the industry's digital future, he has plenty of evidence to back him up.

If we all agree that the oil and gas sector is likely to survive well into the second half of this century and beyond, then getting digital is indeed fundamental. Safety, sustainability, effectiveness and profitability can all be enhanced by what Lervik presents as the 'democratisation' of data. This means getting information, often in real time, to more people who can act on it quickly and cost effectively to improve an asset's performance.

The Austrian operator OMV, a Cognite client which operates 30 oil platforms with more than 300 wells, is a good example of digitalisation in action. The company is developing a digital twin of its assets to support asset integrity, reduce downtime and generally cut the cost of maintenance. This, the interested parties believe, will reduce planned shutdowns by as much as 30%, boosting production by around 700,000 barrels a year. The value of these efficiency gains is estimated at a whopping $38 million a year and if, as seems likely, the oil price holds its own for the time being, this can only get better.

Using 3D imagery, the digital twinning of assets can produce a virtual world to support practical, remote decision-making. It brings more people into the loop and it provides a unified view of maintenance activities. No wonder Lervik is bullish about this and other automated developments, such as a digital discharge and emissions project which Cognite is working on with Aker BP and the World Economic Forum. The ultimate aim is to reduce an operator's environmental footprint and improve transparency along the road to Net Zero. And the proof of course is usable data. ■

Nick Cottam

Shutterstock

Conversion Factors

Crude oil

1 m^3 = 6.29 barrels

1 barrel = 0.159 m^3

1 tonne = 7.49 barrels

Natural gas

1 m^3 = 35.3 ft^3

1 ft^3 = 0.028 m^3

Energy

1000 m^3 gas = 1 m^3 o.e.

1 tonne NGL = 1.9 m^3 o.e.

Numbers

Million = 1 x 10^6

Billion = 1 x 10^9

Trillion = 1 x 10^{12}

Supergiant field

Recoverable reserves > 5 billion barrels (800 million Sm^3) of oil equivalents

Giant field

Recoverable reserves > 500 million barrels (80 million Sm^3) of oil equivalents

Major field

Recoverable reserves > 100 million barrels (16 million Sm^3) of oil equivalents

Historic oil price